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Timothy P. Murray
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Richard K. Sullivan, Jr.
Secretary

Mark D. Sylvia
Commissioner

August 18, 2011

HAND DELIVERED
Mark D. Marini, Secretary
Department of Public Utilities
One South Station
Boston, MA 02112

RE: **Petition to Address Interconnection**

The Department of Energy Resources ("DOER"), the executive agency charged with establishing and implementing the Commonwealth's energy policy and programs, is committed to improving the interconnection process in Massachusetts. Based on our review of existing tracking data, applications for interconnection have increased every year. As more projects apply, it is clear that the current process needs to be adapted to meet ever increasing demand. To address this need, DOER partnered with the Massachusetts Clean Energy Center ("MassCEC") to commission a report that detailed the interconnection situation in Massachusetts and crafted innovative solutions. MassCEC, with guidance from DOER, issued a request for proposals to hire a consultant to address these and other interconnection issues in Massachusetts, and selected KEMA Inc. ("KEMA"). KEMA surveyed multiple stakeholders, including Massachusetts utilities, distributed generation owners and developers, and engaged many subject matter experts, and submitted this report on July 25, 2011.

DOER hereby submits this report to the Department for its review and requests that the Department open an investigation on interconnection.[1] Whether that investigation is to be part of the Department's ongoing proceedings in DPU 11-11 or a separate proceeding, DOER leaves to the Department's discretion. Suffice it to say, DOER believes that the need for prompt action on interconnection should drive the Department's procedural approach to addressing this important issue.
Based on the findings in KEMA's report, DOER respectfully requests that the scope of this proceeding encompass the following DPU Investigation, Findings and Orders.
DOER respectfully requests the Department to:

[1] The report is also available online at http://bit.ly/MADGIC

1. Establish how long it should take the utilities to process an interconnection application in the best of circumstances, with adequate staffing, and then establish binding timelines for the interconnection process;

2. Establish what it would cost the utilities to provide interconnection services that meet those timelines and determine if utilities are currently under-collecting;

3. Design an incentive structure that encourages the utilities to engage the appropriate staffing to meet these newly-established timelines. Among the incentives considered should be increased application and interconnection fees, penalties for failing to meet the timelines and creating incentives within Service Quality metrics;

4. Revise the tariff to mandate the creation of a uniform on-line interconnection application system consistent with recommendation 3 on pages 118-121 of the KEMA report;

5. Require the utilities to establish transparent criteria for what triggers the requirement of various system upgrades paid for by interconnecting customers, and a formal process by which the utilities update the criteria;

6. Require the utilities to continue ongoing collaborative efforts with DOER, including the new technologies working group, interconnection workshops, and other efforts that DOER may direct;

7. Hire at DPU an ombudsperson who will hear and quickly resolve interconnection disputes between developers and utilities;

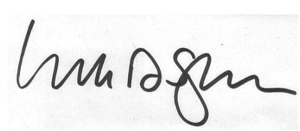
8. Require the utilities to increase collection of certain interconnection project tracking data;

9. Require the utilities to collect and publish information to optimize results of DG site selection, with specific attention given to recommendation 3.5 on pages 120-121 of the KEMA report; and

10. Revise the tariff to require utilities to address area networks.

Given the need for prompt action on interconnection, we leave it to the Department's able discretion whether to address interconnection in DPU 11-11 or another proceeding. DOER looks forward to presenting these recommendations in greater detail in the resulting proceedings.

Sincerely,



Mark Sylvia
Commissioner

Massachusetts Distributed Generation Interconnection Report

Final Report

Prepared For:

Massachusetts Department of Energy Resources and
Massachusetts Clean Energy Center

Burlington, MA, July 25, 2011

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Notice

This report was prepared by KEMA, Inc. in the course of performing work supported by the Massachusetts Clean Energy Center (MassCEC) and the Massachusetts Department of Energy Resources (DOER). The opinions expressed in this report do not necessarily reflect those of MassCEC, DOER or the Commonwealth of Massachusetts, and reference to any specific product, service, process, or method does not constitute an implied or expressed recommendation or endorsement of it.

Acknowledgements

KEMA would like to acknowledge the Massachusetts Clean Energy Center and the Massachusetts Department of Energy Resources, both of which have been very supportive throughout this project. Thanks and acknowledgment are due to the following:

Richard Sullivan, Secretary, Massachusetts Executive Office of Energy & Environmental Affairs
Steven Clarke, Assistant Secretary for Energy, Massachusetts Executive Office of Energy & Environmental Affairs
Mark Sylvia, Commissioner, Massachusetts Department of Energy Resources
Gerry Bingham, Massachusetts Department of Energy Resources
Mike Wallerstein, Massachusetts Department of Energy Resources
Patrick Cloney, Executive Director, Massachusetts Clean Energy Center
Andy Brydges, Massachusetts Clean Energy Center

In addition, we would like to acknowledge and thank the project advisors that worked closely with the KEMA team, and the panel of national reviewers. These individuals gave generously of their time and expertise to ensure that this work was as fully informed as possible:

Thomas Basso, Senior Scientist, National Renewable Energy Labs
Michael Coddington, Distributed Energy Systems Integration, National Renewable Energy Labs
Francis H. Cummings, former coordinator, Massachusetts DG Collaborative (2002-2009).
David Forrest, Interconnection staff, ISO-New England, Inc.
Marija Ilic, professor of Electrical and Computer Engineering (ECE) and Engineering Public Policy (EPP), Carnegie Mellon University
Dr. Dana L. Levy, D.Eng., PE; Industrial Research Program Manager, NYSERDA
Dr. William Moomaw, Professor of International Environmental Policy, Fletcher School of Law and Diplomacy, Tufts University
Joseph Pendergast, Energy Supply Program Manager, Harvard University
Maureen Quinlan, Distributed Generation Specialist, NC Solar Center at NC State University
Douglas Schmidt, Project Manager, Harvard University
Ernst Scholtz, PhD; Program Manager, Grid Automation, ABB Corporate Research
Michael Sheehan, Interstate Renewable Energy Council (IREC)

Mary Smith, Associate Director of Energy Supply and Utility Administration, Harvard University
Laurel Varnado, Policy Analyst, NC Solar Center at NC State University
Joseph Weidman, Partner, Keyes and Fox LLP and Interstate Renewable Energy Council
William Wendling, PE; Wendling Consulting LLC

Finally, we wish to acknowledge in particular the contribution of Gerry Bingham and Mike Wallerstein (DOER) and Steven Clarke, Assistant Secretary of Energy, for their continuing effort, steady hand and patient guidance throughout the project.

Last but not least, we thank all those in both the DG community at large – installers, developers, project owners and advocates – and all of the utility staff who work diligently to interconnect their projects in the safest and most effective manner possible. We hope this report will contribute to advancing the effort toward which you all strive: a cleaner, safe and efficient electricity system for the Commonwealth.

For KEMA Inc.

Erika Morgan, Project Manager
Karin Corfee, Principal in Charge
Nellie Tong
Josh Venden
Aaron Schneider
Jessica Baldic

Executive Summary

Distributed Generation (DG) is a relatively new segment of the Massachusetts energy industry, yet one that has grown with increasing speed over the last five years. Comprised initially of small scale wind turbines and residential solar electric (photovoltaic or PV) systems, DG has broadened to include community scale wind, neighborhood PV, commercial scale installations of PV, small scale hydro and microturbines, combined heat and power (CHP) applications and soon fuel cells. To the extent that these smaller scale, independent generators generate more electricity than they consume on-site, their net excess generation can – once the generator is interconnected – provide power for their neighbors, community and the wider electricity marketplace.

This Study was undertaken to provide a snapshot of the status of DG interconnection activities in the Commonwealth, and a reference to several important related developments nationally. A heavy emphasis has been placed on the experience of the MA DG industry – owners, installers and project developers, those most familiar with the strengths and the weaknesses of current MA processes as these exist today, in both rule and actual practice.

The first three sections of the report examine the several sources of data used in this study: the experience of MA DG applicants as revealed in an on-line survey; the position of MA utilities as captured in interviews; the utility tracking data of DG projects over time; and a targeted national literature search, on specific issues related to the main focus. The State-by-State review also set the stage for further exploration of three specific issues of importance to Massachusetts; each of these is a focus of further exploration in Sections 5 through 7. Sections 3 through 7 each end with discussion of ways the Commonwealth might choose to move forward toward additional progress in the future. Section 8 brings these themes together, in a summary of the key findings, discussion of the implications of those findings and list of recommendations.

Highlights of the Key Findings

- The volume of DG applications in Massachusetts has increased sharply. This growth has outstripped the utilities' ability to process interconnection requests in a timely manner. Total volume of interconnection applications grew four-fold for National Grid and NSTAR between 2004 and 2010. The total KW volume of interconnection applications reviewed by either the Expedited or Standard path has grown seven-fold over the years between 2004 and 2010. Continued growth is likely.

- The current review process, while lauded for its successes in years past, is no longer up to the demands of the current application volume. Applicants express significant dissatisfaction with the overall time period required for completion of application reviews under both the Expedited and Standard review processes. A high percentage of Expedited and Standard reviews appear to be missing the Maximum Time Frames by a significant amount. The rate at which utilities have been able to complete interconnection reviews was overtaken by the rate of applications in 2009.
- A redesign of the Interconnection application and review process is now necessary. Planning for a new process should begin immediately. That process should:
    - Take maximum advantage of online information and electronic communications, to vastly reduce if not eliminate the delays due to incomplete filings and the exchange of information between the parties;
    - Build in and make automatic the tracking of each process step, to result in clear metrics of performance; and
    - Be designed to anticipate and accommodate the high-volume penetration of DG that will accompany continued growth in the Commonwealth's clean energy industry.

The report concludes with a list of ten Recommendations, each broken into subcomponents as needed. These Recommendations are summarized in the matrix below. The numbering of the Recommendations shows the KEMA's team's estimated priority order; the final priorities rest of course with the Massachusetts agencies and stakeholders.

Matrix of Recommendations

Recommendation	Implemented By	How
1.0 Charge DOER to reconvene DG Collaborative	DPU, DOER	Order/ Direction
2.0 Require additional utility information	DPU; utilities	Order, to cover:
2.1 Monthly utility reports	Utilities to provide	– Required monthly tracking data
2.2 One-time data request		– Common upgrades, decision standards
3.0 Require IC Process Redesign	DPU	Initiate Proceeding, to define:
3.1 Identify participation		– Stakeholder participation
3.2 Process parameters		– Budget, timeline, required functions
3.3 Process objectives		– Principles and process objectives
4.0 NOI: Planning for High Penetration DG	DPU; utilities	Order initiating proceeding
5.0 Fix Dispute Resolution process	DPU	Order or Staff action
5.1 Ombudsman role		
5.2 Ombudsman judgments		
6.0 Reconvene DG Collaborative	DOER	Extend invitation(s), convene & support.
6.1 Update Simplified path	Collaborative	Collaborative process to identify changes and create Framework
6.2 Review Expedited path		
6.3 Update IC seminars		
6.4 Create Stepwise Framework		
7.0 DG IC education campaign	DOER	Takes the lead to promote
7.1 Interconnection workshops	DOER	Continue/ increase schedule; Incorporate new content (from 6.3)
7.2 Distribution System Maps	Utilities	Voluntary posting of distribution system information.
8.0 Federal-State Clarifications	DOER	
8.1 Convene multi-State working group	DOER	Invite other states; define the objective; set agendas.
8.2 Develop guidance	DOER	Oversight/ management of Multi-state working group
9.0 Network Interconnections	DOER;	Reconvene Collaborative; oversee 9.1
9.1 After IEEE 1547.6	DOER; Collaborative	Determine impact of 1547.6
9.2 Research European experience	DOER	Actions left to DOER judgment
9.3 Enhance network monitoring	DOER; utilities	Monitor NSTAR Demonstration; replicate if possible
10.1 Organization and Staffing	Utilities	
10.1 DG Interconnection metrics	Utilities	Determine and report against metrics appropriate for current volume & staffing
10.2 Internal process redesign	Utilities	Ensure that current organizational structure and staffing levels are appropriate to meet the metrics set in 10.1

1. Introduction

Since its inauguration in January 2007, the administration of Massachusetts Governor Deval L. Patrick has been committed to the growth of the clean energy industry. In 2008, the landmark Green Communities Act[1] increased the RPS in Massachusetts to targets of 15% by 2020 and 25% in 2030. Early commitments by the Administration to the target of 250 MW of clean energy by 2017 have repeatedly emphasized the ability of these emerging technologies and growing clean energy companies to bring both financial savings and environmental benefits to the Commonwealth and employment to the region.

Key to the success of these technologies and companies, as well as to the success of this strategy overall, is the ability of these clean energy technologies to produce clean generation on a cost-effective basis. The cost of interconnecting distributed generation projects to the electricity distribution system is a critical factor in the project cost equation. For the purpose of this report, KEMA defined "distributed generation" (DG) as the onsite generation of electricity on the customer side of the meter and operating in parallel with grid power.[2] DG may be generation powered by solar (photovoltaics or PV), wind, small hydro, on-site biomass generators, gas-fired microturbines or fuel cells and generators and It does not include emergency generation.

The current interconnection standards and process were developed by the Massachusetts Distributed Generation Collaborative in 2003, with minor revisions submitted to the DPU and approved in 2007.[3] Since then, as solar photovoltaics (PV), wind, combined heat and power (CHP) and other clean technologies have found increasing opportunities in Massachusetts, the volume of interconnection applications received by the four Massachusetts investor-owned

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[1] See "An Act Relative to Green Communities", signed by Governor Patrick on July 2, 2008, posted at http://www.malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.

[2] "Distributed generation is any electricity generating technology installed by a customer or independent electricity producer that is connected at the **distribution system** level of the electric grid. This includes all generation installed at sites owned and operated by utility customers, such as photovoltaic systems serving a house or a cogeneration facility serving an office." From the Massachusetts Clean Energy Center's "Interconnection Guide for Distributed Generation", available at http://www.masscec.com/masscec/file/InterconnectionGuidetoMA_Final%281%29.pdf

[3] See March 3, 2003 Massachusetts Distributed Generation Interconnection Collaborative, Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts; see also D.T.E. 02-38-B, February 24, 2004, Order on Model Interconnection Tariff ("Tariff") implementing uniform standards for interconnecting DG, Massachusetts Department of Telecommunications and Energy; see also D.T.E. 02-38-B, May 31, 2005, 2005 Annual Report, Massachusetts Distributed Generation Collaborative, Section 1.6; see also D.T.E. 02-38-C, June 30, 2006, 2006 Final Report, Section 2 and Attachment A: Redline of Model Tariff.

utilities has grown substantially and the scale and complexity of DG projects has also increased. In 2011, the Administration made a commitment to address the challenges of the interconnection process, long perceived by many in the DG industry as a barrier to the timely and cost-effective interconnection of DG systems.

1.1 Study Purpose and Objectives

KEMA has been retained by the Massachusetts Clean Energy Center (MassCEC) to work with MassCEC and the Massachusetts Department of Energy Resources (DOER) on a "review of generator experiences with the existing Massachusetts Distributed Generation (DG) interconnection process".[4] The study examines the experience of many parties in their efforts to interconnect DG projects in the Commonwealth. As such, a core point of reference throughout this report is the Massachusetts Model Interconnection Tariff,[5] hereinafter cited as the "MA Model Interconnection Tariff" or "MA Tariff" in the text. This report will provide a springboard for policy recommendations to be filed by DOER in the current Massachusetts Department of Public Utilities (DPU) docket considering changes to present interconnection processes, both as those are codified in the MA Tariff and/or in related activities by the DG applicants, interconnecting utilities and other associated parties.

Based on the Scope of Work, KEMA holds the following objectives for this study report, namely to:

- Provide a status report on current DG interconnection activities in Massachusetts;
- Provide a snapshot of industry experience with the current MA DG interconnection process;
- Discuss the challenges inherent in this process from the perspective of both the DG industry and the four major Massachusetts investor-owned utilities;
- Examine examples of interconnection policies in other states that illuminate alternatives Massachusetts policy-makers might consider to improve the current DG interconnection process;

[4] "Scope of Services" Attachment A, to Work Order 11-1 between Massachusetts Clean Energy Center and KEMA, Inc., hereinafter "Scope of Work" (SOW). Page 4.

[5] Downloadable from http://www.env.state.ma.us/dpu/docs/electric/09-03/82009noiapb.pdf.

- Provide an informed discussion of the challenges and issues that characterize this topic from the vantage point of an objective third-party non-industry participant; and

- Offer recommendations for potential policy changes based upon these findings for consideration by DOER.

1.2 Study Context

Massachusetts policy has been favorable to clean renewable sources of energy for decades. The Commonwealth originally enacted net metering for renewable energy systems in 1982; subsequent amendments in 1997 raised the cap on net metered systems to 60 KW. The net metering rules have been amended several times since, with the most recent action in September 2010 increasing the aggregate cap on net metered capacity for municipally-owned DG systems.[6] Massachusetts also has one of the region's first Renewable Energy Portfolio Standards (RPS), originally passed in 1997. Like many MA renewable energy policies, the RPS has also been the focus of continuing refinement, with the latest set of revisions passed in December 2010 and effective January 7, 2011, enacting the Solar Carve-Out. The RPS specifies tiers of renewables and sets an increasing scale for the penetration of each Class to an overall target of 20% by 2020. The Solar Carve-Out mandates that retail electricity suppliers must satisfy an increasing fraction of their RPS obligation from Massachusetts-located interconnected PV facilities. These Solar Carve-Out Generating Units represent PV systems under 6 MW in size and interconnected after December 2007.[7]

In addition, the Massachusetts Green Communities Act (GCA) passed in July 2008 created two other important incentives for DG. The GCA increased the rate of growth in the state's RPS to 1% per year, mandating renewables reach a total of 15% of MA electricity delivery by 2020, 25% by 2030, continuing to grow without cap. The GCA also created the Alternative Energy Portfolio Standard (APS). The APS requires load serving entities to meet 5% of their MA load from CHP, co-generation or other forms of "alternative energy" sources.[8] For the purposes of this study, technologies eligible under the APS are considered within the definition of DG.

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[6] House Bill 2058, passed September 27, 2010 and enacted October 15, 2010. Sections 25-30.

[7] MA RPS summary at DSIRE
http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MA05R&re=1&ee=1.

[8] For further detail on both the MA RPS and APS, see the DOER website at http://www.mass.gov/energy/rps.

In short, this is the context around the topic of interconnection of distributed generation in Massachusetts. The policy environment is robustly supportive of new dispersed, smaller, often renewably-fueled and low- or zero-emission generating technologies. These incentives have sparked considerable investment by electricity customers and clean energy developers to bring new DG projects to fruition. Yet all of these projects must be interconnected to the electricity distribution system in order to realize the energy, economic and environmental advantages that both customers and policy-makers seek to capture.

1.3 Study Methodology

Under contract to MassCEC, KEMA's Scope of Work consisted of seven tasks, culminating in a summary report. Immediately upon project kick-off March 18, the KEMA team began current development of a web-based survey to assess the views of the DG industry and of background papers on key project topics. Survey responses have been supplemented by phone interviews with utility personnel directly involved in the review of DG interconnection applications. Results from both the survey and interviews has been compared, correlated, supplemented by findings of national research done through a review of literature and experience in states with leading interconnection processes.

Finally, each component of this effort has benefited from the input of several project advisors. These experts have provided references, resources, review and comment at different points in the study process:

- Francis H. Cummings, former Policy Director of the Massachusetts Renewable Energy Trust and facilitator/coordinator of the Massachusetts DG Collaborative from 2002 through 2009.
- Michael T. Sheehan, Interstate Renewable Energy Council (IREC)
- Joe Wiedman, partner, Keyes and Fox LLP and IREC;
- Gerry Bingham and Mike Wallerstein, DOER.

The remainder of the report is organized in the following sections:

- **Section 2 –** Task 1, Data Collection – A discussion of the DG industry survey of interconnection experience, and summary of results. This section also describes the design of the qualitative interviews with utility interconnection staff.
- **Section 3 –** Task 2, Analysis of Projects Seeking Interconnection – This section analyzes data available from the State agencies concerning the number and type of DG

seeking application. The section summarizes trends in the applications and highlights issues, many of which are discussed further in subsequent sections of the report.

- **Section 4 –** Task 3, State-by-State Review – This section sets the stage for subsequent sections, by summarizing the MA DG interconnection process generally. Using a variety of national sources, we then examine the current MA process against "Best Practice" states. This section also highlights areas where the current MA process can be improved. This section also highlights states with processes from which MA can learn.
- **Section 5 –** Task 4, State and Federal Jurisdiction – This section is the first of three topics to be explored in depth. This section is organized to provide background on the issue, a discussion of problematic areas as identified by the DG industry through survey data, a summary of current utility approaches to the issues, and discussion of possible lessons and approaches for further consideration.
- **Section 6 –** Task 5, Secondary Distribution Networks – This section explores in depth one of the most difficult and contentious areas of current interconnection experience. As in the previous section, Section 6 provides background on the issue, summarizes the challenges as experienced by the DG industry and current utility approaches to the challenges, and includes a discussion of possible approaches going forward.
- **Section 7 –** Task 6, System Planning, Integration and Transparency – This section examines the issue of DG integration into the electrical system from the perspective of the DG industry and the utilities. We identify key integration and transparency issues and draw on both examples from other states and progress in other venues to identify possible directions for further work.
- **Section 8 –** Task 7, Final Report – This last section summarizes the main findings of the report, drawing on the key data and insights from each of the previous sections. Draft recommendations from each previous section are summarized and prioritized in this section.

2. Qualitative Data Collection

To understand the MA DG interconnection process and its challenges, KEMA performed a series of primary data collection activities, including an industry survey with email or phone follow-up, and utility phone interviews.

2.1 Interconnection Participant Survey

KEMA conducted a comprehensive survey of interconnection participants in MA. The purpose of the survey was to understand the experience of interconnection applicants, identify challenges to the timely interconnection of DG and solicit industry recommendations to these challenges. The objective was to return at least 50 unique complete survey responses from entities with experience in the MA interconnection process.

2.1.1 Survey Design and Implementation

KEMA developed a draft industry survey with input from DOER staff and the project team advisors. Within one week of the project's kick-off meeting, the survey underwent a series of on-line tests, and was published on April 1, 2011. MassCEC and DOER distributed the survey to potential respondents, including:

- Stakeholders from the 2006 DG Collaborative Report [9];
- DPU Service lists of all DG related proceedings, including the DG Collaborative, the NSTAR standby rate, and net metered customers;
- Project proponents that have sought interconnection in Massachusetts since 2004 (e.g., new entities responding to recent incentives; state projects; major renewable DG installers; etc.); and
- Interconnection applicants that have been identified as having experienced DG interconnection difficulties involving technical standards, delays or required upgrades.

The on-line survey collector was open until April 11 to give stakeholders over one week to respond. For those who missed the deadline or wished to submit supplemental input, a

[9] D.T.E. 02-38-C, June 30, 2006, 2006 Final Report, Massachusetts Distributed Generation Collaborative, Introduction.

spreadsheet tool was posted on the Mass DG and Interconnection website[10] to collect additional input.

The following shows the steps and the timeline of the design and implementation of the survey:

- March 25-28: Draft survey developed and reviewed internally within KEMA;
- March 28-30: External review by project advisors, DOER and MassCEC;
- March 30: Conference call between KEMA, DOER and project advisors was held to discuss and finalize survey contents;
- March 31: Survey was coded into online survey tool SurveyMonkey, tested internally by the KEMA team and project advisors, and the survey cover letter drafted;
- April 1 morning: Final online testing and review by KEMA, DOER staff, and staff from the Massachusetts Executive Office of Energy & Environmental Affairs;
- April 1 afternoon: Online survey was launched through MassCEC and DOER announcements;
- April 5: Survey reminder was sent by DOER; and
- April 11: The on-line survey collector was closed.

2.1.2 Survey Structure and Logic

To encourage participation, the survey only has two questions for which an answer is required (versus voluntary). The first required response asked whether the respondent has completed or is in the process of completing interconnected DG projects in MA. Since this project is focused on stakeholders that have experience with MA DG interconnection process, respondents who answered "No" were not able to complete the survey.

The second required question addressed the confidentiality of survey responses. KEMA is sensitive to the desire of many respondents to maintain the confidentiality of their replies. For reporting purposes, KEMA required respondents to select from three levels of confidentiality. Table 2-1 below describes these levels and how survey responses are used in this report for each corresponding level.

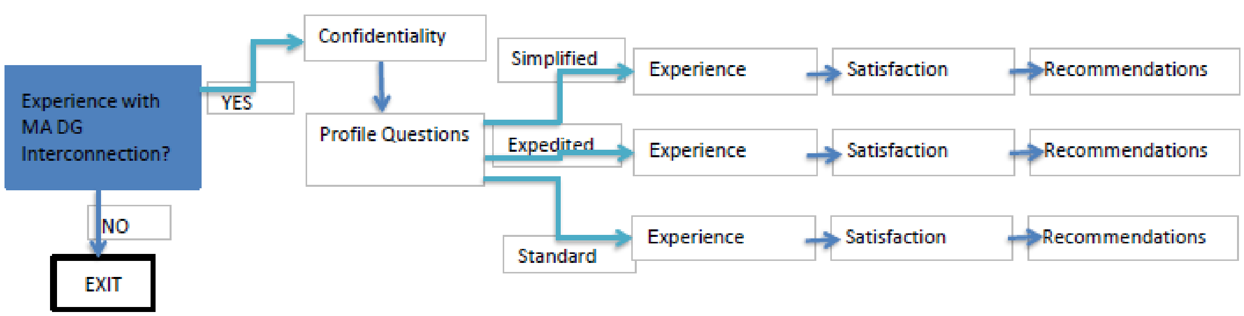
[10] http://sites.google.com/site/massdgic/.

Table 2-1 Confidentiality Levels in KEMA On-Line Survey

Confidentiality Level	Description of how survey responses will be used
Fully Opt-Out of Confidentiality Policy	The authors may share and quote any of the respondents' responses.
Partially Opt-Out of Confidentiality Policy	The authors may anonymously quote from the respondents responses (quotes may be used, but there will be no identification of the source).
Fully Confidential	Utilize the answers for aggregating results, but keep individual respondents' responses fully confidential.

The survey has four main sections that attempt to capture each respondent's background, experience, satisfaction with the current interconnection process and policy, and recommendations. The current MA interconnection process has three related routes or pathways: Simplified, Expedited and Standard. Each process has slightly different procedures and requirements. To reflect these, the online survey was designed with three unique tracks, one for each pathway[11]. Where possible and useful, the responses of the three process paths are reported separately. The survey's logic is shown in Figure 2-1 below:

Figure 2-1 Structure of the KEMA On-Line Survey



[11] Respondents with experience in more than one process were directed to the survey track with the more complicated process. For example, a respondent with experience in both the Simplified and Standard processes was directed to the Standard process survey track.

Copies of the three surveys are attached in Appendix B.

2.1.3 Survey Respondents

KEMA closed the survey collector April 11, 2011, with a total of 89 completed responses[12]. Most respondents heard about the survey from DOER's email announcement. Figure 2-2 below shows how respondents learned about the survey.

Figure 2-2 Sources of Survey Respondents

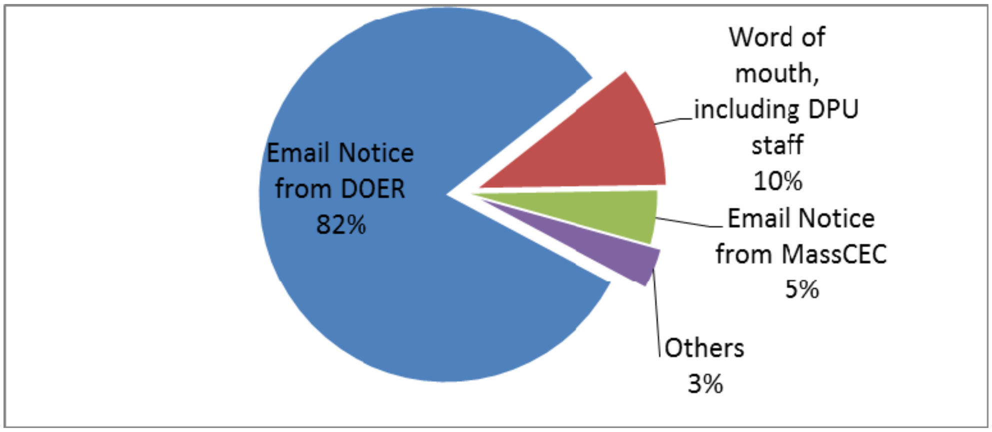
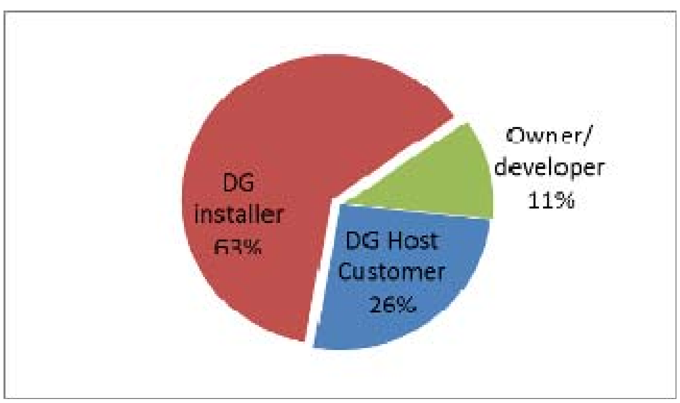


Figure 2-3 below shows profiles those who completed the survey. The respondent group includes an array of installers, developers and customers with significant experience spanning the spectrum of DG interconnection projects in MA.

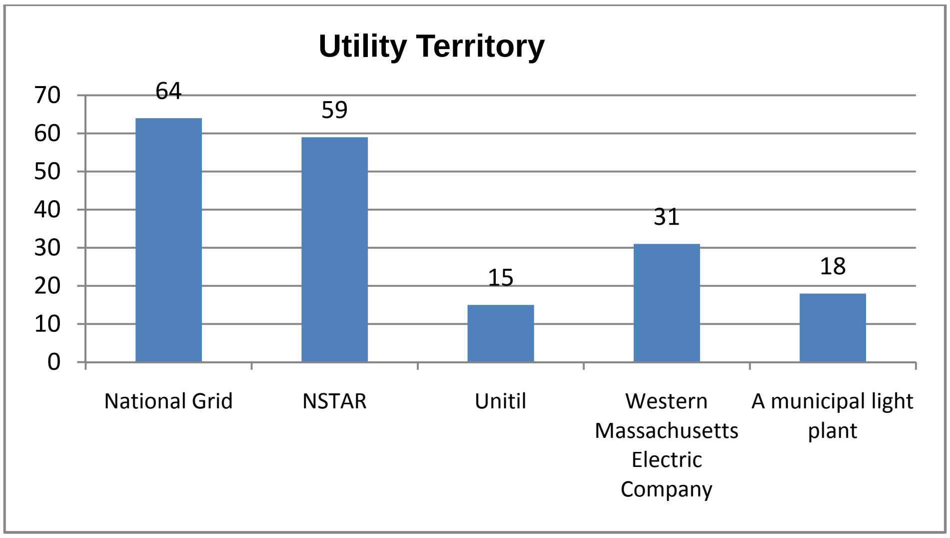
Figure 2-3 Categories of Survey Respondents

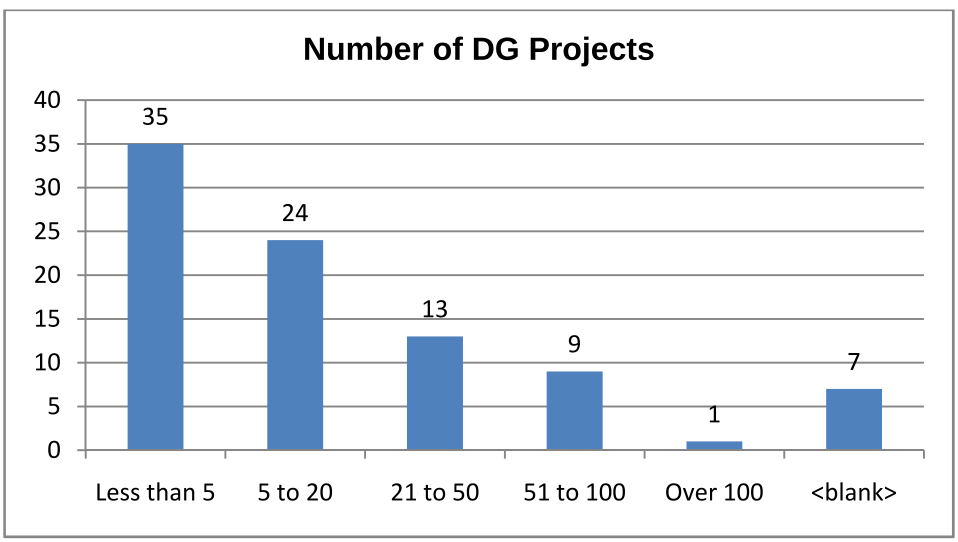


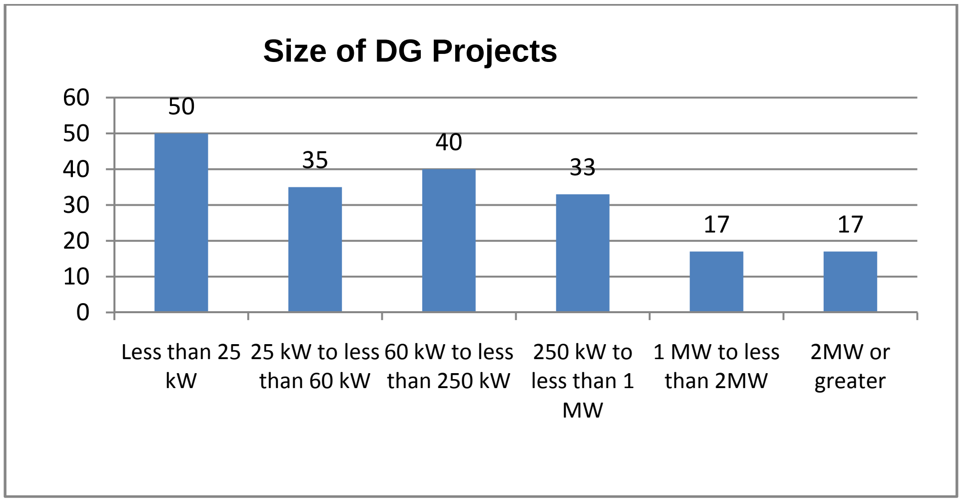
[12] The total of 89 includes both confidential and non-confidential responses, and is therefore the total of all unique (non-duplicative) responses.

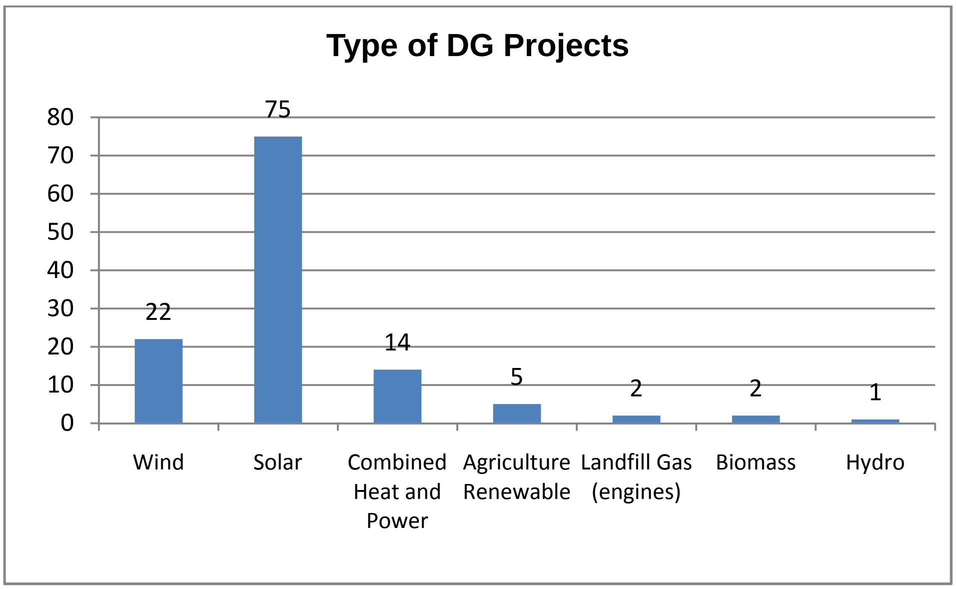
The survey sought feedback from those experienced with the MA DG interconnection process. Figure 2-4 details that experience base by summarizing the 89 respondents in terms of the type, sizes and number of their projects and the utility territories in which their projects were located. The Y axis in each of the following charts refers to the number of respondents in each category, as does the data label over each bar. We note that the 89 responses cover a total of 187 projects. These were well dispersed in size and utility territory, yet concentrated heavily in PV.

Figure 2-4 Respondents' MA Interconnection Experience



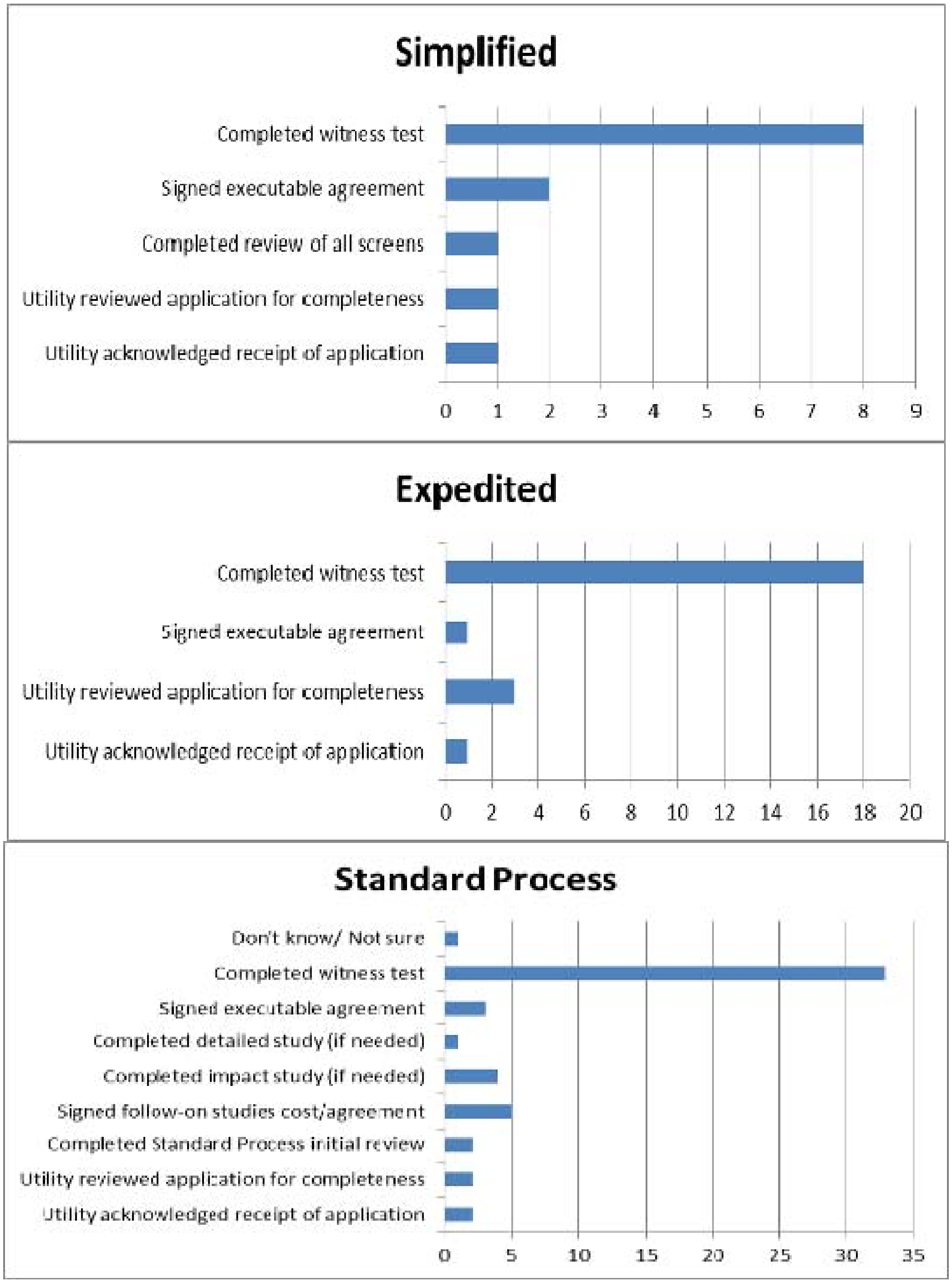






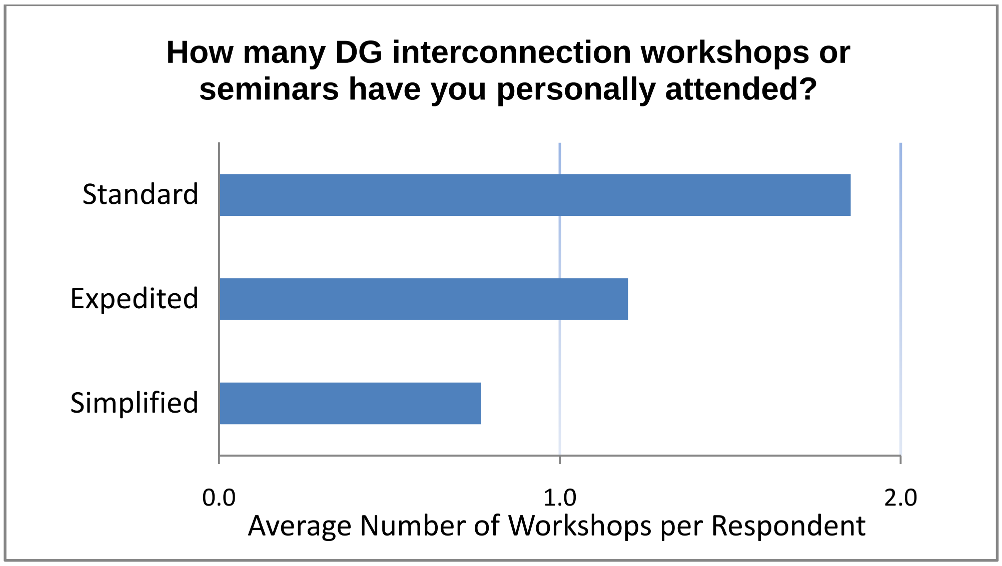
Given that the survey sought respondents with first-hand experience of the MA interconnection processes, we required that all respondents have at minimum submitted an application and begun the interconnection process. Figure 2-5 below summarizes the status of the most advanced interconnection project completed by each survey respondent. The majority in all three categories have completed witness tests on at least one project and therefore experienced the full interconnection process.

Figure 2-5 Status of Respondents' DG Projects



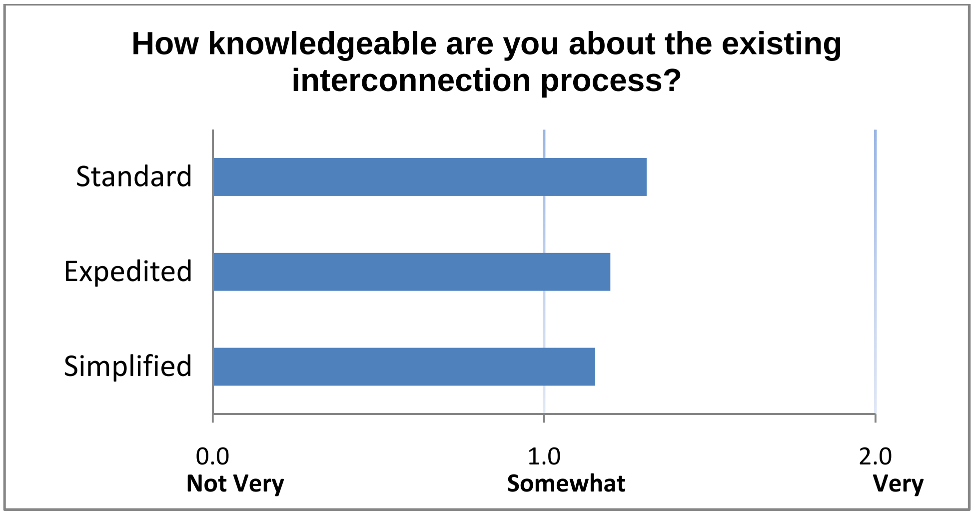
Finally, the survey also asked respondents to characterize their level of understanding of the process. Figure 2-6 summarizes the number of workshops on the DG interconnection process attended on average by respondents experienced in each of the current review paths. Standard applicants have attended on average well more than one workshop. Applicants to the Simplified path, however, have averaged less than one workshop per respondent. This suggests that some number of applicants apply under the Simplified path without attending any workshop.

Figure 2-6 DG Survey Respondents Workshop Attendance



Despite their direct experience interconnecting projects, however, and their level of workshop attendance, respondents in all categories consider themselves only 'somewhat' knowledgeable of the current process. This is shown in Figure 2-7 below.

Figure 2-7 Survey Respondents DG Process Knowledge



Further discussion of the individual findings specific to the key topics of this investigation are included in the respective sections later in this report.

To ensure that KEMA fully understood the survey responses, we conducted several follow-up emails and phone interviews following review of the survey results. This follow-up was to clarify specific respondent comments, resolve ambiguities in their replies, and provide an opportunity for further comment where it appeared to be requested. For example, if a survey respondent indicated or suggested on the survey that he or she has an experience or extensive recommendations that cannot be easily stated in the confines of the online survey, KEMA contacted the respondent for an interview. A total of 6 individuals were contacted in follow-up to their survey responses, through either email or phone interview. Findings and insights from these follow-up contacts has been incorporated into the topical sections of this report.

2.2 Utility Interviews

To ensure a fully balanced and comprehensive review of the interconnection experience, KEMA also conducted a series of qualitative interviews with utility company managers directly involved in the interconnection process.[13] The four Massachusetts investor-owned utilities (IOUs) – National Grid, NSTAR, Western Massachusetts Electric Company (WMECo) and Unitil – represent a significant spectrum of service territory, customer base and operating size in

[13] These interviews did not include the municipal electric utilities or rural coops, as the community-owned utilities (COUs) are not covered by the existing state interconnection tariff and associated requirements.

Massachusetts. They range from National Grid, a multi-state utility serving roughly half of the state, to Unitil, which serves four communities in north-central Massachusetts.[14]

We pursued several objectives in these interviews, namely to:

- Gather utility perspective on issues and challenges raised by the DG industry;
- Gain insight on the internal processes associated with the current interconnection application review process;
- Elicit reaction to possible changes in interconnection volume and processes;
- Invite suggestions and recommendations for future changes to improve the overall duration and efficiency of the interconnection process.

The utility interview guide is included in Appendix C. The interviews were designed to be 45-60 minutes in length, with an opportunity to submit additional comment afterward as needed.

In keeping with KEMA standard practice for qualitative interviews of this sort, all interviews were conducted in a fully confidential manner. KEMA confirmed at the beginning of each interview that a) the respondent would be speaking for themselves, based on their own experience, not as a representative of their Company; b) that comments provided in the interview would not be associated at any time with the respondent's name or their company, and c) that the respondent was located in a confidential space and able to speak freely. These confidentiality protections are standard KEMA practice for all qualitative interviews.

KEMA developed a list of 22 individuals within the four utilities with direct experience in the interconnection process; candidates were drawn from planning, technical, sales and legal departments. All candidates were notified April 29 that they may be called to schedule an interview.

Interviews were conducted between May 2 and 13 by Erika Morgan (KEMA) and Fran Cummings (project advisor). The project members interviewed a total of eight individuals from the four investor-owned utilities. The findings and insights from these interviews have been incorporated into the relevant discussions of this report.

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[14] Commonwealth of Massachusetts Electric Service Providers – map of service by community. Downloaded from US Department of Energy's Northeast Clean Energy Application Center at http://www.northeastcleanenergy.org/uploads/UtilityProviders-Electric-January06.pdf.

3. State-By-State Review

To place the Massachusetts interconnection experience in an appropriate wider context, KEMA has reviewed the available literature that summarizes DG interconnection policies, rules and processes in other states. By looking at interconnection best practices, MA policy makers hope to identify both the strengths of the current process and examples from other states that have addressed the areas where MA processes need further improvement.

In this review, KEMA drew on the considerable body of work that has been done to improve interconnection policy and rules across the country. The complete list of works reviewed is included in the project reference list, Appendix E. The main categories of references consulted for the State-by-State review include:

- Publications and other references from national organizations active in interconnection policy. These include the Interstate Renewable Energy Council (IREC), the Network for New Energy Choices, and the Solar America Board of Codes and Standards (Solar ABCs). A sample of the wealth of information on interconnection from these sources reviewed by the project team includes:
    - DSIRE database "Database of State Incentives for Renewables and Efficiency", an offering of US DOE, the North Carolina Solar Center and the Interstate Renewable Energy Council, located at www.dsireusa.org.
    - "Freeing the Grid 2010: Best Practices in State Net Metering and Interconnection Policies", December 2010 Network for New Energy Choices. MA State profile on page 59. www.freeingthegrid.org
    - Fox, Kevin T. and Keyes, Jason B.; "Comparison of the Four Leading Small Generator Interconnection Procedures", prepared by the Interstate Renewable Energy Council, October 2008. Available at: www.solarabcs.org/interconnection
    - IREC. *Model Interconnection Procedures*. 2009 Edition.
    - Sheehan, Michael T., and Cleveland, Thomas; "Small Generator Interconnection Procedures Screens: Updated Recommendations to the Federal Energy Regulatory Commission (FERC) " prepared by the Interstate Renewable Energy Council (IREC), July 2010. Available at www.solarabcs.org/FERCscreens.

- Efforts by utilities in both Massachusetts and elsewhere that worked diligently to improve their own interconnection practices. The following examples were highlighted by project advisors from IREC; a more thorough national search may well identify other notable developments:

  - Hawaiian Electric Company. *For approval to modify Rule 14H – Interconnection of Distributed Generating Facilities Operating In Parallel With The Company's Electric System.* Transmittal No. 10-01. Effective Date: February 8, 2010.
  - NSTAR Electric Company. *Standards for Interconnection of Distributed Generation*. Effective October 1, 2009.
  - Pacific Gas and Electric (PG&E). *Wholesale Distribution Tariff Reform. Generator Interconnection Procedures.* March 4, 2011.

- Efforts by other regional transmission organizations and national organizations concerned with the efficiency and effectiveness with which electric utilities are able to integrate and utilize cost-effective distributed generation resources. Key references from these sources include but were not limited to:

  - California Public Utilities Commission. *California and Distributed Generation*. NARUC Summer 2010. www.naruc.org.
  - ISO New England*. Forward Capacity Market and Interconnection Processes for New Generation*. May 6, 2009.
  - NARUC. *Model Interconnection Procedures and Agreement for Small Distributed Generation Resources*. 2003. www.naruc.org.
  - Midwest ISO. *Integration of Renewables at the Midwest ISO*. NARUC Winter Meetings February 2010. www.naruc.org.

In this section of the report, we draw on the work of other states, utilities, regions, and national experts to provide further insight into how MA policies might be strengthened. We identify areas where Massachusetts is already strong, where it may still improve, and we look to other states and jurisdictions for ideas and directions for change.

3.1 Background on DG Interconnection in Massachusetts

State interconnection policy is compromised of a number of different components ranging from eligible technologies, to project timelines and fees, to system integration, and more. Through many years of consistent work to improve interconnection processes, Massachusetts has earned its place as one of the nation's leading states in effective DG interconnection. This fact is evidenced by the consistently improving scores received by Massachusetts in "Freeing the Grid", the national score card of interconnection and net metering published by the Network for New Energy Choices.[15] In 2010, Massachusetts was one of four states to receive an interconnection letter grade of "A" in interconnection policy. This high score caps a steady progression made by the Commonwealth since 2007, the last year MA was awarded a "C" in both net-metering and interconnection practices.

To be awarded an "A", Massachusetts has met the "best practice" level in virtually all categories of the "Freeing the Grid" score card. In addition to achieving high scores generally, Massachusetts has emerged as one of the leading states in two particularly key components of interconnection policy:

- **Interconnection fees** – Massachusetts is one of two states nationwide that caps interconnection charges and waives fees for net-metered customers[16]; and
- **Interconnection timelines** – Massachusetts is one of four states nationally that has set timelines that are shorter than FERC standards.[17]

Without discounting this steady improvement and achievement, however, the discussion in Section 4 highlights the fact that – especially in the eyes of the growing MA DG industry – considerable improvement is still required in order to meet these timelines. Continued improvement in the technologies and economics of distributed generation require continuous process improvement on the part of the interconnecting utilities. While Massachusetts timelines, fees and other policies may look good in a national context, we discuss in Section 4 that the MA industry has a less complementary view of the Commonwealth's actual interconnection success. This largely reflects the fact that the timelines, while laudable targets, are aspirational in nature and frequently go unmet. Finally, in the eyes of an industry growing rapidly in response to the Patrick Administration's hospitable policy environment, the DG interconnection process must continue to improve.

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[15] Network for New Energy Choices. Freeing the Grid. 2010 Edition.

[16] Ibid At the time of the 2010 report, net metered projects could be up to 60 kW, with the fee waived for projects under 10 kW. In 2011, net metered projects can now be up to 2 MW but must also pay a fee above 10 kW.

[17] Ibid. We note, however, as discussed in Section 3, that these timelines are set as guidelines not mandates, and there is no penalty on the utility of the targeted timeframe is exceeded.

Table 3-1 below compares elements of interconnection policy in Massachusetts to the three other states that received the top scores in “Freeing the Grid”: Maine, Utah, and Virginia. In the case of two other components of interconnection policy – external disconnect and standard interconnection forms – there were several states that were not top scorers overall but were leaders in these individual policy components. To realize “best in the nation” status against the criteria in “Freeing the Grid”, MA would address shortfalls in these five areas:

Table 3-1 MA Policies in Perspective: Areas for Improvement[18]

Interconnection Policy	Best Practice States	Current MA Policy	Recommendation for MA
External Disconnect	NJ, ME, UT	MA requires a redundant external disconnect switch at the utility's discretion.	Prohibit redundant external disconnect switches. Eliminate utility discretion.
Technical Review Screens	ME, Utah, VA	MA has partially adopted the screens.	Use the FERC standard screens.
Standard Form	Ohio, NY, ME	MA is moving in the right direction and received a positive score.	Update standard agreement with additional friendly clauses. Review Ohio and NY standard form agreements as potential templates.
Insurance	ME, UT	MA currently requires additional liability insurance on the project.	Prohibit requirements for liability insurance for non-inverter based systems under 50 kW or inverter-based systems under 1 MW.
Rule Coverage	ME, VA	MA rules currently cover investor-owned utilities only.	Establish that interconnection standards cover all utilities in the state, including municipalities.

3.2 Guidance from Elsewhere

The “Freeing the Grid” criteria provide useful and important guidance into the needs of the DG industry and the “best practices” to fulfil those needs. At the same time, a national scoring

[18] Table drawn from Network for New Energy Choices. Freeing the Grid 2010 Edition. Because this table draws on recommendations in NEC’s 2010 report, we have not listed here recommendations from this study that may fall outside these areas. The recommendations from this work are summarized in Section 8.

system cannot be fully cognizant of each state's challenges in the implementation of its stated policies. The Scope of Work for this project directed KEMA to examine the experience of other states in five key areas. The examples provided below provide an introduction to the more detailed discussions of each issue is provided in the following sections of this report.

- Jurisdictional Clarity – Overlaps and ambiguity in areas of Federal versus State jurisdiction over the interconnection of DG is a complex and contentious area that pivots on issues of constitutional law. To date, the few states have tackled these issues have done so through commission dockets currently open. We discuss steps for Massachusetts consideration in Section 5.
- Network Interconnection – Interconnection of DG in secondary networks poses particular challenges in several areas. Examples of states making progress with this challenge are listed below; further discussion of these and other approaches is included in Section 6.
- Updating Mechanisms – To keep DG interconnection processes in step with the pace and volume of demand, processes must be continually updated. We examined mechanisms deployed elsewhere for continuous improvement of interconnection processes, as well as ways to improve DG dispute resolution processes. These are addressed in Section 7.
- Decision Transparency – The term "transparency" is used in this context to refer to the basis on which decisions are made during the interconnection process and the communication of those decisions. As such, transparency covers the use of published standards, decision screens, witness tests and certificates of completion, and planning and mapping tools. States with notable examples from which MA can learn are described below; further examination of the options for MA and related recommendations are included in Section 7 and 8.
- Streamlined Procedures – As shown clearly by the growing gap between applications submitted versus approved (Section 4), new processes and mechanisms are required to better respond to the increasing volume of DG applications. These may include fast-track processes, 'batch' or cluster processes and /or other streamlined approaches to DG interconnection, as ways to supplement, improve or replace the current sequential processes. Several states provide insight into significant ways to address these challenges – the examples described below will be further addressed in Sections 7 and 8.

Jurisdictional Clarity

The Federal government and the states have developed independent processes for the review and approval of the interconnection applications for projects of different sizes and market intentions. In general, FERC has jurisdiction over wholesale market transactions, while the states regulate local distribution companies and their provision of wires services in their service territories. These two sets of issues come together in the instances of DG projects that seek to interconnect into the local distribution system and may or may not sell their output to customers beyond the local distribution company to which they are interconnected. States like California and MA, where growing volume of applications for larger DG projects has set the stage for sales beyond the receiving distribution companies, have begun to see a variety of issues arise over questions of jurisdiction, notification and cooperation on these related but distinct levels of review.

This topic is explored in more detail in Section 5. In brief, however, our research suggests that questions of jurisdictional ambiguity can be resolved in one of two ways. The first would use a collaborative multi-party approach to explore the issues and facilitate voluntary use of the resulting guidance. This approach has been used successfully in Massachusetts in the past. The alternative is to bring specific questions of jurisdiction forward for deliberation in a DPU docket.

The latter mechanism has been utilized in other states. For example, a case underway in before the California PUC has examined issues of jurisdiction in the context of that state's proposed Renewable Auction Mechanism.[19] Rather than bring each question into formal debate in MA, however, we think a less formal approach may prove more effective. As discussed further in Sections 5 and 8, both the DG applicants and the Commonwealth will be better served by a process that approaches questions of jurisdictional ambiguity in a collaborative manner. By a) monitoring jurisdictional findings in other states, b) piloting or deploying solutions on a voluntary basis, with c) the option of more formal DPU action if needed, the MA DG parties may develop jurisdictional clarity in a manner that is ultimately more effective and successful than formal regulatory action.

[19] CPUC "Decision Adopting the Renewable Auction Mechanism" Decisions 10-12-048, issued December 17, 2010, and "Order Granting Clarification and Dismissing Rehearing", 133 FERC 61,059 (October 21, 2010) as referenced in IREC "Draft Resolution E-4368 of the Energy Division Addressing Pacific Gas and Electric Company's Advice Letter 3674-E", dated November 9, 2010.

Network Interconnections

Secondary distribution networks pose challenges to DG interconnection. Area networks are particularly challenging, yet these are found primarily in 11 Massachusetts urban areas. Networks are distinctly different and more complex than radial lines for reasons that reflect the basic design of the distribution system. To date, the interconnection of DG has been particularly challenging in spot networks[20] and essentially disallowed in any of the areas of Massachusetts served by an area network. This has effectively removed the option of DG for a large percentage of the population and larger commercial customers in the State. The issues behind disallowing DG interconnection in area networks are discussed more fully in Section 6. In this section, we examine the lessons from two states where DG interconnection in area networks is permitted under some circumstances.

Examples from Other States

Texas – The Texas PUC standard rules governing interconnection of DG cover the situation of DG interconnecting into area networks. In recognition that this interconnection is more challenging and possibly less likely, the TX rules provide specific guidance to utilities on their response to this application. The TX rules:[21]

- Mandate approval for all inverter-based DG "unless total distributed generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration";[22]
- Mandate approval of other DG where the DG provides less than the customers total load "unless total distributed generation (including the new facility) on affected feeders represents more than 25% of the total load of the secondary network under consideration";[23] and

[20] Unless the project qualifies for the Simple Spot Network path in the MA Tariff; regrettably, very few projects to date have so qualified.

[21] Texas Administrative Code, Chapter 25, Section 25.211, subsections (h) and (i), page 302.

[22] Ibid, subsection (h) (1)

[23] Ibid, subsection (h) (2)

- Require utilities, when a network application is received, to:
    - Meet with the applicants to advise them of the difficulties of interconnecting into an area network;
    - Charge no fee for the pre-interconnection study when the applicant is inverter-based DG under 20 kW in size. For larger applications, the utility must provide an estimate of the study cost in advance; and
    - If the pre-interconnection study is initiated for the network application, it must be completed within four weeks, the utility must share the written report with the applicant, and the study must consider both the costs and benefits of the interconnection.[24]
- Allow utilities to postpone reviewing DG applications if interconnection is proposed on a feeder where DG installations already exceed 25% of that secondary network's total load. In this instance, the utility will:
    - Conduct interconnection and network studies to determine the amount of new DG that can be safely added to that feeder; and
    - Complete the studies within six weeks and then resume review of the application.
- Allow utilities to reject network interconnection of DG when they can demonstrate specific reliability and safety concerns associated with that application.
- Require utilities to work with applicants to resolve DG network interconnections in a mutually satisfactory way.[25]

Maryland – Like many states, Maryland has a tiered system for the review of DG applications. MD has created a separate review category for DG systems that will not export power to the grid. These systems are typically significantly smaller in size than the load of the customer receiving the generation. DG systems seeking interconnection to an area network must also be inverter-based, be under 50 kW in size and require no new facility construction by the utility.[26]

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[24] Ibid. subsections (h) and (i).

[25] Ibid.

[26] Maryland, State of; Annotated Code of Maryland. Title 20, Subtitle 50, Article, §2-113, 2-121, 5-101, 5-303, and 7-306. "Small Generator Interconnection Standards". Downloaded 5/1/11 from http://www.dsd.state.md.us/comar/SubtitleSearch.aspx?search=20.50.09.*

Mechanisms to Update and Resolve Issues

Over the last ten years, most states have shown steady improvement in their DG interconnection processes, as attested by multiple national reports and sources.[27] At the same time, most states do not accomplish this updating through the use of standing committees or on-going meetings. Rather, DG processes are typically refined through the opening of a PUC docket to address pertinent issues and/or customer complaints.

Sound DG Interconnection policy requires both a strong platform of basic rules or guidelines, and either penalties for non-performance and/or a dispute resolution process that promises justice for any aggrieved party. Against developer timelines that require a relatively quick, relatively inexpensive process to get a resolution, time- intensive processes do not lead to efficient resolutions.

The MA Tariff provides a formal dispute resolution process. As discussed further in Section 7, this process has both strengths and weaknesses. Our search of examples from elsewhere was intended in part to learn about mechanisms that have proven successful in addressing these weaknesses.

Some states provide frameworks to encourage informal dispute resolution processes, with the intent that formal complaints to a commission can be avoided. A reasonable framework allows the parties – typically utilities and developers – to negotiate their own resolution and then implement a binding agreement for the PUC to formalize. An alternate approach allows the parties to select a third party arbiter. The key is to identify an arbitrator that adequately understands the complex technical, legal, and policy problems entailed in interconnection disputes. These mechanisms typically allow the parties to split the costs of arbitration and agree in advance to consider the arbiter's decision as binding.

Examples from Other States

Colorado – Colorado exemplifies states that show continuous improvement in DG policies. Since passage of the state's Renewable Portfolio Standard in 2004, the Colorado Public Utilities Commission, Legislature, and Governor have continued to improve distributed generation

[27] Among them IREC's "Connecting to the Grid" website, "Freeing the Grid" annual reports and other sources.

policies in the State.[28] In particular, net metering and associated rules for distributed generation in Colorado have continually been updated and improved. In 2009, the legislature removed the 2 MW cap on net-metered DG and instituted a rule that allows up to 120% of annual on-site consumption.[29]

California – Since the early 2000s, California has been at the forefront of designing and instituting distributed generation interconnection standards. CA's "Rule 21" sets specific operating and interconnection requirements for DG, and sets a model tariff that has been adopted by the state's IOUs.[30] California's "Rule 21 Working Group" has served as a mechanism for consideration of changes to the Rule as needed. CPUC announced in April 2011 that the Rule 21 Working Group, which last met in 2008, has been reconstituted to address areas of the current CA rule that require updating, including transparency, updated technical screens and updated cost-allocation methods.[31]

Decision Transparency

As stated earlier, we use the term "transparency" to refer to the visibility that participants have into the decisions made in the interconnection process. Throughout the survey responses and comments, DG applicants expressed concerns about the manner in which decisions were made, whether across utilities and even within utilities. The industry's key complaint under this heading is that utilities do not provide enough information to the developer. They seek several different types of information, including:

- A means of tracking the status of their application as it moves through the review process;
- A clear understanding of the factors that determine whether their application moves forward to the next step in the process, and at what pace;

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[28] Colorado Revised Statutes C. R. S. 40-2-124 (2009) Article 2. "Public Utilities Commission – Renewable Energy Standard.

[29] Ibid., and Colorado Public Utilities Commission "*In the Matter of Proposed Amendments to the Rules of the Colorado Public Utilities Commission Relating to the Renewable Energy Standard".* Decision No. C09-0990 in Docket No. 08R-424E Decision on Exceptions and Adopting Rules Associated with the Notices of Proposed Rulemaking Under Decision Nos. C08-1001 and C09-0817. Adopted September 2, 2009. http://www.dora.state.co.us/puc/DocketsDecisions/decisions/2009/C09-0990_08R-424E.pdf.

[30] DSIRE database, CA interconnection profile, viewed at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA21R&re=1&ee=1.

[31] IREC "Connecting to the Grid" website at http://irecusa.org/2011/04/cpuc-to-reopen-rule-21-working-group/

- Tracking mechanisms reported on-line, published or otherwise transparent to applicants. In addition to following the progress of their own application, the posting of aggregated process metrics fosters accountability for the process overall;
- Fully transparent criteria for passing the review screens in the MA Tariff – that are both published and followed;
- Notification when screens are not passed, and on what basis that decision was made;
- Clear protocols for the conditions and/or circumstances under which the utilities require upgrades; and
- The ability to review the utility's decisions and/or bring in outside engineering assistance for that review.

In this section we set forth the issue and examine examples from other states that offer models for Massachusetts to consider. Additional discussion of decision transparency is provided in Section 7 as an important element under the broader heading of DG's role in utility planning.

Examples from Other States

Hawaii – Hawaii is currently considering a proposal to improve decision transparency for interconnection procedures. The proposed process involves two steps:

- Step 1 – If a customer or developer fails any utility screen, the utility is required to send the applicant a written description of the step(s) failed and why.
- Step 2 – If the customer or developer fails the supplemental review, the utility is required to provide written disclosure of the conclusions of the review and the basis on which they were made.

At each stage, after receipt of the utility's report, the proposed process provides for a developer to then hire an engineer to review the utility's findings for reasonableness. The proposed study report and all information required for the review is proprietary to the utility, with the standard exception that PUC staff retain the ability to review the information. We note an additional element to the Hawaii proposal that we favor for implementation in MA as well, as discussed in

Section 3. Hawaii encourages utilities and developers to meet before an application is submitted to discuss the potential project and share information. [32]

California – The California PUC and the California Solar Initiative have developed an official public reporting site that presents “actual program data, exported from the California Solar Initiative online application tool each Wednesday”.[33] The website provides public statistics that can be utilized by developers to improve their decision making process. The website provides a dataset that includes information such as timelines to reach project milestones, average cost per watt of a solar system, and installed capacity by utility. While some of this information is available in Massachusetts, information on the size and locations of installed DG would be beneficial to MA applicants. This is particularly true for developers considering projects on lines where other projects are already interconnected.

Streamlined Interconnection Procedures

The need to streamline interconnection procedures is evident throughout all data collection for this study. As described in Section 4, delays in the current interconnection process are characterized by both applicants and utilities as exchanges of incomplete information followed by delays at the hands of the other party. Applicants report being asked for information not initially requested, while utilities report delay while applicants secure information required to complete the review. To reach the level of efficiency all parties seek, however, a more substantial organizational “re-engineering” of the application process is clearly required. We address this topic in Section 4 and continue that discussion in Sections 7 and 8.

One form of process re-engineering would replace the current step-wise series of sequential review steps with a “cluster” or “batched” approach. In this model, interconnection applications received during a particular time interval are considered simultaneously. Where applications in the same batch propose interconnection to the same or related circuits, the impacts of those interconnections are evaluated together. A batch process may also allow similarly sized DG projects to share the costs of one study. To the extent that batched projects are on the same feeders, they may also be able to share the costs of required upgrades.

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32 Ibid.

33 http://californiasolarstatistics.ca.gov/ While this site does not include as much information related to DG interconnection as is recommended in this report, it does make publically available application and tracking statistics that is currently unavailable in MA.

Use of the cluster approach is still very new, however, such that there is insufficient experience to determine whether the approach may also have downsides to the parties and/or result in negative outcomes. To date, the cluster approach has only been implemented in California and is under consideration in Hawaii. For these states, the cluster approach has been driven by a backlog of customers. Currently, no other states are pursuing the cluster approach.

Use of the clustering or batch process may be viewed positively or negatively by applicants, based on their perception of the speed of the process the batching would replace. If a developer judges that their application will be reviewed more quickly, efficiently or result in a less costly outcome through the clustered process, the change to a batched process may find support among the industry. We discuss this and other possible process changes in Section 8.

Examples from Other States

California – California is the first state to try out a 'batched' or cluster approach, which CA IOUs began to implement in late 2010. PG&E, for example, issued its preliminary process overview to stakeholders in December, accepted comments on its draft tariff until early February 2011 and submitted the proposed tariff amendment to FERC in March. Under this approach, DG applicants above 2-3 MW may opt for three different pathways. The first two "Fast Track" and "Independent Study Process" apply to different projects according to the complexity of the project review; with applicable fees and screens, and a published review time of 10 business days (Initial Review) and 20 business days for supplemental review.

Under the third process, however, the "Cluster Study Process", the utility groups applicants for the purposes of two levels of study. Published fees apply, as do published maximum review periods in calendar days. Projects are grouped in cluster of similarly sized projects, and the utility determines and presents to the applicant a "worst case" cost for all studies and fees in the review process. This preliminary analysis informs developers with limited financial capacity so that they may drop out of the process before incurring more cost. The second stage, completion of the interconnection study itself, is then done with only those developers that have the financial capacity to see the study through to the final analysis.[34]

It is important to point out the California approach has clear rules about cost sharing and that the cost sharing allocation is a heavily litigated process. One objective of the California approach is to ensure that all projects in the interconnection queue have the financial resources,

[34] Personal communication with Joe Wiedman, Fox & Keyes LLP and. IREC. April 12, 2011.

timing and other elements of project viability that will enable them to see the interconnection process through to the end.[35] An additional step underway in California is the synchronization of the ISO Batch process with the programs and policies of the State RPS and CPUC.

Hawaii – Hawaii is currently proposing to implement an interconnection process under which developers are given the option to undergo a joint interconnection study – in other words, 'batch' or 'cluster' – if they are on the same feeder and everyone on the feeder agrees. In this approach, placement in the interconnection queue is crucial to cost allocation. Smart parties will agree to a cost allocation prior to undergoing the study rather than waiting for the interconnection study since the first two interconnections on the feeder may have no issues but the third interconnection requires major upgrades.[36]

[35] Ibid.

[36] Ibid.

4. Analysis of Projects Seeking Interconnection

Massachusetts has focused significant attention on the interconnection of DG for over ten years. Under the auspices of the Massachusetts Renewable Energy Trust at the Massachusetts Technology Collaborative from October 2002 through January 2009, the state facilitated an on-going stakeholder process with the utilities, representatives of the DG industry and other stakeholders. This initiative helped ensure not only that the State's current DG interconnection practices are strong but that lines of communication between utilities and many participants in the DG industry have also remained robust. More specifically, the DG Collaborative compiled tracking data from the four participating electric utilities on DG projects in the interconnection processes.

The following section analyzes the application tracking data from the sources available to KEMA. Direct comparisons between years were made to the extent allowed by the data. Following a description of the tracking data sources and analysis, the sections that follow discuss key findings from the tracking data. Where appropriate, data from the on-line survey has also been included in these sections. The balance of Section 4 consists of:

- Section 4.1 – Tracking Data Reviewed – A summary of the tracking data on which this section's analysis is based;
- Section 4.2 – Characterization of MA DG Projects – By process pathway, DG type and size, 2004 through 2010;
- Section 4.3 – Interconnection Costs – Analysis of survey respondent satisfaction with and expectations of interconnection application fees, study fees and upgrade costs, and respondents and utility staff views on cost allocation;
- Section 4.4 – Timelines – A summary of all data on the sources of delays from both the utility and industry perspectives; applicant expectations of the process compared to current experience;
- Section 4.5 – Application Volume – By company, for the years 2005 through 2010, mapped against average process times; and
- Section 4.6 – Discussion of Potential Solutions.

4.1 Tracking Data Reviewed

Utilities have been responding to requests for tracking data from the Massachusetts DG Collaborative since 2002. The amount and quality of data has varied from year to year. The following analysis is based on utility interconnection tracking data over the four years in which data was collected, from 2004 to 2010. To the extent possible, the data is broken down by the form of the interconnection process utilized by the applicant's review (.i.e., Simplified, Expedited and Standard application processes) unless otherwise indicated.

The primary data files provided for and utilized in this review were:

- 2004-2005 DG dataset per the MA DG Collaborative – Specifically, the eight calendar quarters ending in March 2006;[37]
- 2009-2010 DG dataset provide by MA DOER; and
- DPU 11-11 Attachment A summary of all DG.

The current MA Tariff was based primarily on the consensus recommendations of the DG Collaborative. Minor revisions were submitted in June 2006[38]. At that time, a total of roughly 1 MW of DG interconnection applications had been studied by the Collaborative for a two-year period as part of the basis for their tariff recommendations made at that time. As discussed in Section 1.1, the intervening years have seen an array of new programs and incentives. In the period from 2006 to 2010, interconnection activity in Massachusetts has increased dramatically. The following sections describe several changes in the volume and type of interconnection activity over this time period.

4.2 Characterization of DG Projects

KEMA examined the data sets described above to better understand past and present trends in Massachusetts DG activity. Our analysis began with a summary of the respondents, then breaking the DG volume down according to the interconnection pathways under which the

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[37] D.T.E. 02-38-C, June 30, 2006, 2006 Final Report, Massachusetts Distributed Generation Collaborative, Section 3.4 and Attachment D: Two-Years of Tracking Data through March 2006 and Attachment E: Responses to Eight Questions about Interconnection Data Tracking.

[38] The most recent revisions to the MA Model Interconnection Tariff were made in 2010 as part of the legislative action that increased the net metering cap. Commonwealth of Massachusetts, House bill 5028, passed September 27, 2010. Sections 25-30.

applications were reviewed: Simplified, Expedited and Standard. Since data was not available on the Simplified for all periods, the following charts show Standard and Expedited applications only.

Figure 4-1 DG Interconnection Applications by Path and Project Size

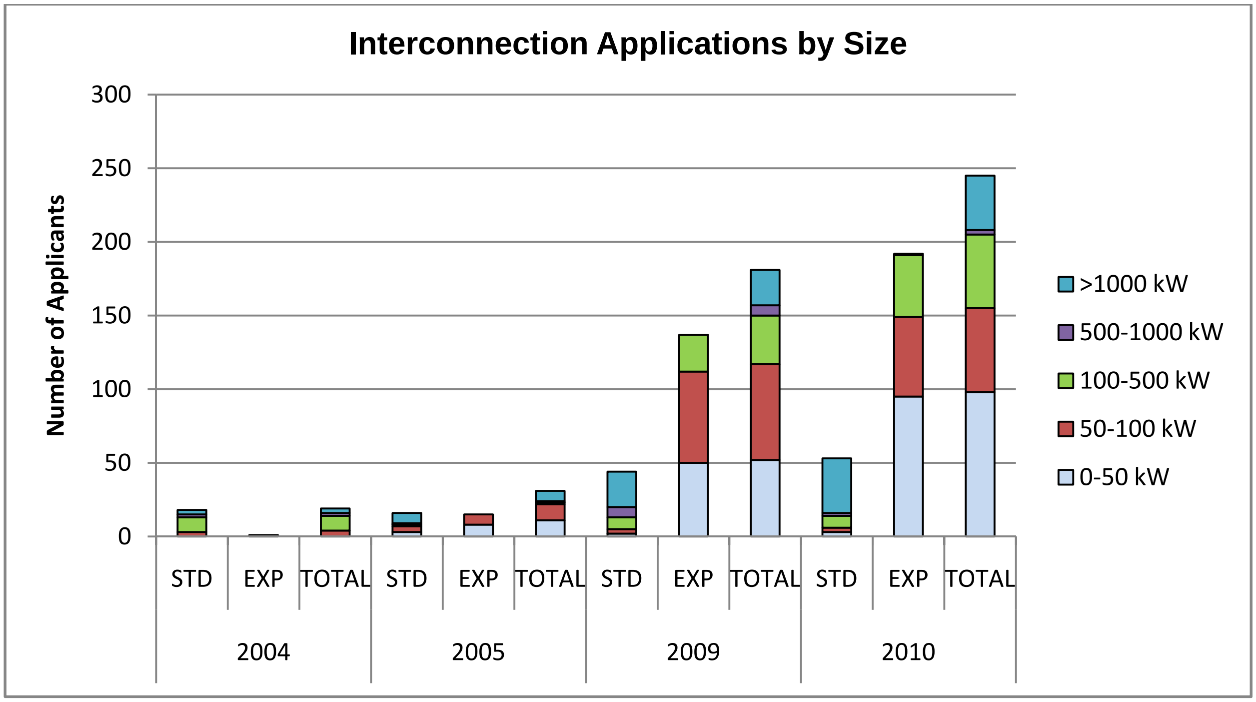


Figure 4-1 shows the significant increase in Standard and Expedited applications that has occurred over the 2004-2010 time period. The growth in the number of Expedited applications has been particularly notable. Growth in two size categories also suggests the following observations and implications:

- The number of projects 1 MW and over has increased. Larger installations generally take longer to study due to a greater impact on the power system.
- The increase in smaller installations (0-50 kW) suggests that a significant number of smaller projects did not qualify for review under the Simplified path.

The latter observation could reflect a) the proposed project location vis a vis the nature of the circuit and associated review complexity, and/ or b) a higher percentage of private individuals or contracts applying that are unfamiliar with the process's steps and requirements and/or lack the resources to provide information necessary to complete screening or impact analysis studies.

Figure 4-2 DG Interconnection Applications by Energy Type

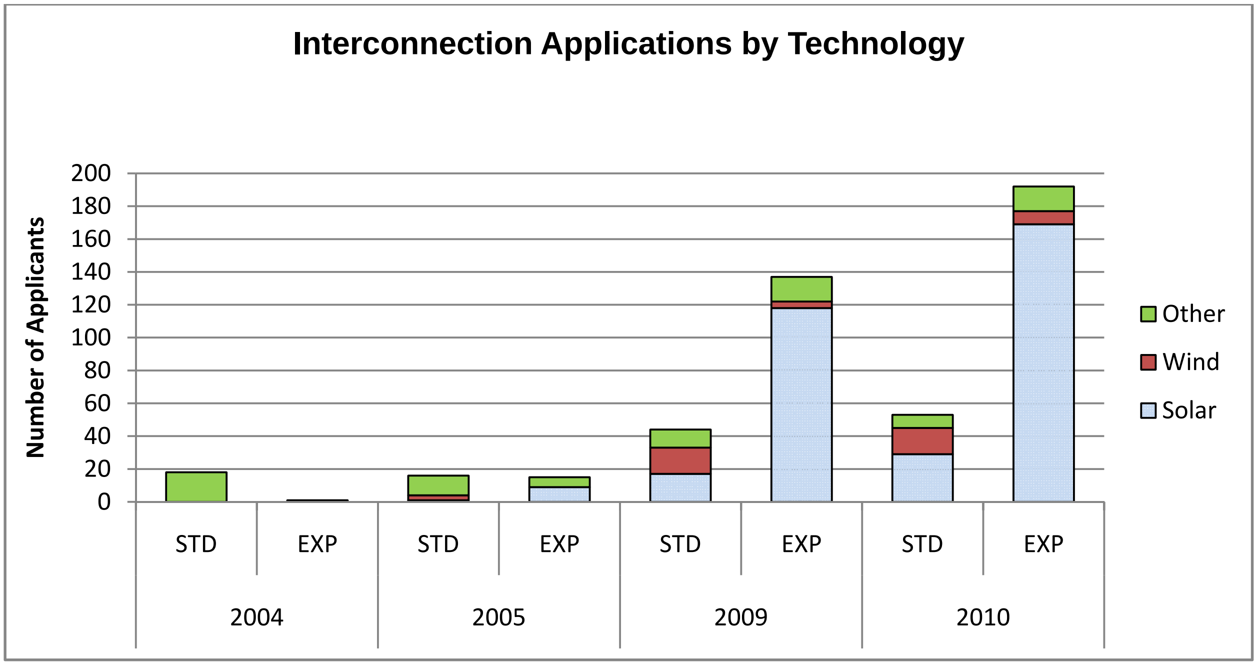
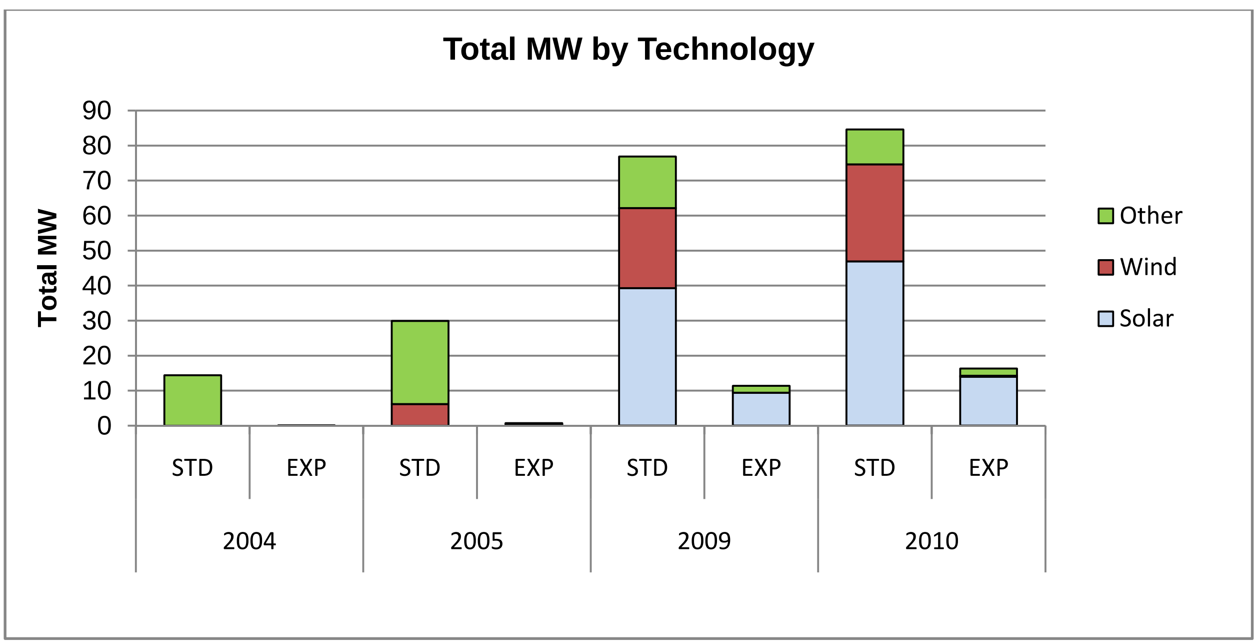


Figure 4-3 Total MW of Interconnected DG by Technology



A comparison of Figure 4-2 and Figure 4-3 above suggests several observations:

In 2004, just about all of the interconnection applications fall into the “other” category. In 2005, this is still predominately true, with the exception of a few wind and solar projects. The “other” category is comprised mainly of more traditional fuel types such as coal, diesel or natural gas. The category also includes hydro and biomass type generation, although the majority of requests were for natural gas fired generators.

By 2009 and 2010, however, more solar and wind systems of all sizes are being interconnected. The volume of solar applications in particular took a striking leap between 2005 and 2009, a fact that may be attributable to the launch of the Commonwealth Solar program and other incentives as described in Section 1.2. The majority of the PV applications that were not reviewed under the Simplified process followed the Expedited path.

The analysis also shows an increase in wind applications between 2005 and 2009. In this case, however, the data shows that these projects were relatively fewer in number (Figure 4-2) but larger in KW (Figure 4-3) and more likely than the solar projects to be screened under the Standard process. Overall, the total kW processed through either the Standard and Expedited Application Processes have increased by nearly seven times in the past seven years.

In summary, our analysis of DG applications since 2004 shows that new systems are growing rapidly in number and in average size. PV and wind systems have predominated, with PV a substantial and growing fraction of the total. In the following sections we probe more deeply into other aspects of the interconnection process, including its costs, timelines and other issues underlying these macro trends.

4.3 Interconnection Costs

This section examines several elements of the cost structure surrounding DG interconnection. Each of the following costs plays a part in determining whether the financial structure of a proposed DG project will go forward:

- Application and study fees – DG applicant satisfaction with present fees, and expectations of reasonable fees;
- Interconnection equipment and system upgrade requirements – Satisfaction with current costs for equipment-related changes; frequency of required modifications.

- Cost allocation – Satisfaction with the current cost allocation policy; suggestions for changes in cost allocation formulae in specific situations.

4.3.1 Application Fees

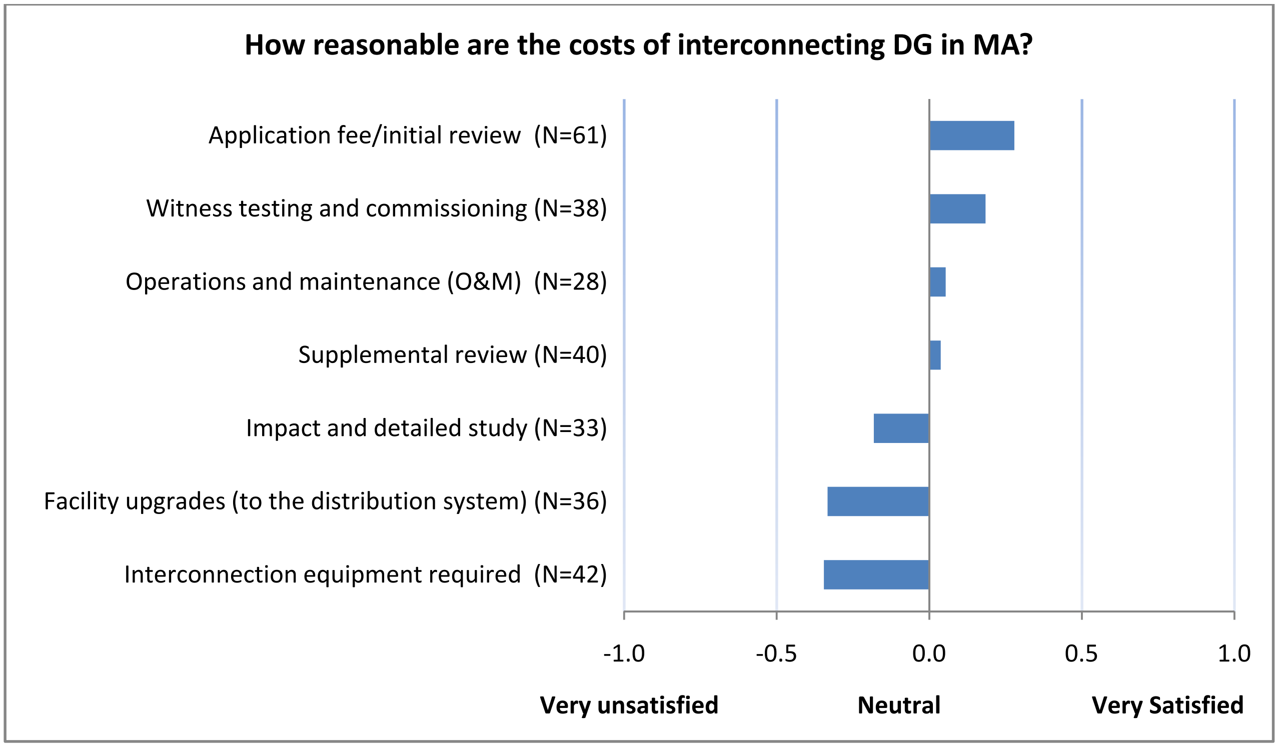
In comparison with other states, Massachusetts has been recognized for the relatively low overall costs of the interconnection process. The national ranking of state interconnection processes conducted by "Freeing the Grid"[39] awards the Commonwealth the highest possible grades for both the interconnection fee and the engineering fees charged during the review process. The high marks scored by MA testify to the national "best practices" in use:

- Waiving application fees for customers <10 kW;
- Capping application fees for all sizes;
- Have fees that are lower than the FERC limits; and
- Using engineering fees that are at fixed rates.

Results from KEMA's industry survey show that MA DG applicants see a more nuanced picture. As shown in Figure 4-4 below, they are satisfied with four of the seven possible cost categories. Fees for the initial review and application, for the witness test and commissioning received favorable scores. Costs for supplemental review and O&M were scored at essentially neutral – slightly more favorable than not. Respondents consider the costs for the studies and the required system modifications more strongly unsatisfactory.

[39] "Freeing The Grid 2010", Appendix A, page 106 for MA scores and page 31 for discussion.

Figure 4-4 Industry Views of Interconnection Costs



Survey comments reveal the depth of this dissatisfaction with the cost of impact and supplemental studies. There is a widespread view among survey respondents that many studies are unnecessary. One survey comment expressed this sentiment as: "….utilities are using the fees…. and the equipment add-ons to shift cost of their failed operation and maintenance of the grid to DG".

The survey also asked respondents about the fee levels they deemed reasonable, for each of the three interconnection paths. Not surprisingly, the majority favor fees that are low and fixed. For the more complex pathways, however, respondents recognize that a fee formula tied to the size and complexity of the proposed project preview process is reasonable. Roughly a quarter of the Expedited applicants and a third of the Standard applicants considered it reasonable to charge a fee of $3 per KW in project size, with a minimum of $300 and maximum of $2,500 per application. Table 4-1 summarizes survey respondents' views of reasonable fees.

Table 4-1 Interconnection Fees Considered 'Reasonable'

	Simplified	Expedited	Standard
$0	85%	24%	26%
$100 or less	7.5%	7%	4%
$101-$500	7.5%	29%	19%
$501-$2500	0%	15%	22%
scaled*	0%	24%	30%
*$3/kW, minimum of $300, maximum of $2500.			

4.3.2 Upgrade Costs

The upgrades required of DG applicants may take two forms: different or additional components, devices or changes required to interconnect the DG to the utility's distribution system, and the installation of additional equipment or facilities by the utility at the applicant's expense, to ensure that the new DG has no negative impacts on other customers on that feeder. Survey respondents express dissatisfaction with both the cost of required upgrades and the unpredictability of those costs. We discuss the transparency of the utilities' upgrade requirements in Section 7. Figure 4-4 in the previous section shows the dissatisfaction of DG industry respondents for both categories of equipment-related cost. Comments attest to a widespread opinion among a significant segment of the industry that these costs are, in the words of one commenter, "….arbitrary and not defined. They need to be standardized between utilities and states…."

The utilities respond that costs for interconnection and systems modifications are a) reasonable and cost-based. Utilities point to the '110% rule' as a counter to the claim of unreasonable or arbitrary costs. Under this requirement, utilities are obligated to estimate their costs for upgrades at within 110% of actual cost, or the utility must absorb that full cost. Several utility interviewees decried this rule as an impediment to an expedited interconnection review: the need for this level of care in estimation forces the utilities to take longer, and possibly complete RFPs to establish the cost of the upgrades they require.

The utilities also point out that project upgrades and/or system modifications impact only a subset of DG applicants, not all. On average, utility respondents report that roughly 35% of Expedited applicants require modifications that impose cost on the applicant. This average varies widely across the four utilities, as it reflects the effects of the planned DG on the specific feeder components and protection regime in place at each DG location. Utility comments also suggest that smaller DG on 13 kV lines have a lower likelihood of requiring modifications, while larger DG on smaller capacity lines has a correspondingly higher likelihood of being required to make system-protecting modifications.

A high fraction of Standard applications, however, require significant project- and/or system modifications. This occurs because a Standard DG project is more likely to be a stand-alone generator, not located on the customer-side of an existing meter. As such, these larger DG projects commonly require a) stand-alone metering; b) primary line extensions, and c) installation of sufficient relays and/or other protective components to ensure that the new DG poses no risk to other customers on that line.

4.3.3 Cost-Allocation

Under the current MA Tariff, the DG applicant bears the cost of both modifications to their own project, and any modifications necessary to interconnect their projects in a manner that protects the safety and reliability of service to other customers on the same feeder. The topic of cost-allocation for the upgrades necessary to interconnect DG has been interwoven with the wider discussion about DG's value to the distribution system. The DG Collaborative has been the forum for much of this debate, particularly in 2005-06 under the auspices of the Distribution Planning Work Group. While the topic of DG's role in utility planning is explored more fully in Section 7, under this heading it is appropriate to mention the Collaborative's work in cataloging the costs and benefits of DG to the distribution system. Based on the work group's analysis,[40] they identified a series of conditions and challenges that would need to be in place and/or otherwise addressed in order to provide a basis for a general finding about the value of DG to the distribution system. Such a finding is prerequisite to any formula for the prospective allocation of DG-related costs to the distribution companies.

While stepping back from any general statement in 2006 in favor of further technical and economic analysis, the DG Collaborative did report that "….DG appears to provide some positive benefits in deferral of distribution investment….within narrow windows of opportunity, based on specific timeframes, need dates and specific feeder lines...." and in combination with "a package of resources that includes energy efficiency and demand response resources."[41]

[40] Attachment G: "DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative" and Attachment H: "Report of DPWG on DG and Distribution Deferral", attachments to the Massachusetts Distributed Generation Collaborative 2006 Report, D.T.E. 02-38-C submitted June 30, 2006.

[41] DG Collaborative 2006 Annual Report page 36.

These “narrow windows of opportunity” – within which the utility may see and acknowledge benefit from the DG – have begun to be apparent as both the volume of DG and its reliability has become better established (see additional discussion in Section 7). To probe current industry and utility thinking on the topic of cost allocation, the survey asked about DG applicants’ satisfaction with the current policy. We also asked about an option under which DG projects on a single circuit might share upgrade costs. 18 percent of respondents favored the current policy, while 82% favored the possibility of a different allocation method. As one commenter stated: “The ‘first-in’ concept should be revised to a standard more like service upgrades, where others that come in second or third provide relief to the first-comer”.

Utility respondents also acknowledge some instances that merit consideration of different cost allocation formulas:

- When applicant-required distribution system upgrades correspond to upgrades already planned by the utility, as for example:
  - “Our policy (on “system improvement values”) is to issue a credit to reduce the DG customer’s cost of distribution facility upgrades, to the extent that part of the work is expected to be needed soon even without the DG, or the work would have been done anyway….”;
  - “Our VP advised us, if we know they (the changes) are coming, and these changes are in the plan, then we do not charge for these….That’s when we ask the engineering group ‘is there something you guys are planning that would change the interconnection we see….”;
- When DG’s added capacity on a specific line can delay or offset planned line upgrades, particularly in areas where the utility is experiencing demand growth:
  - “If there was an upgrade that we thought was needed for other customers and we were planning to do it ‘in a reasonable period’, we’d try to be flexible....”;
- When the initial DG on a specific feeder is followed by subsequent DG projects on the same line:
  - “Maybe we could devise a cost-sharing arrangement that equalizes the “first-in” payee with the “2nd-in” – maybe a percentage of weight based on the DG size you are, and maybe the utility shares the cost as well”.

Each of these and other scenarios suggest opportunities to reduce the interconnection burden on applicants through apportionment of the upgrade costs among all the benefiting parties: the interconnecting DG owner as well as the utility. As the rate of DG applications continues to increase, utilities should anticipate the continuation of these instances and develop cost-allocation formulas that match the share of cost to the share of benefit.

Alternatively, the DPU could mandate a formula under which utilities area required to pick up some or all of the distribution upgrade costs that a) replace more quickly components within the last 5-10 years of their expected life; b) advance the implementation of Smart Grid-enabled and/or “DG-Ready” components (see Section 6, Area Networks) by a year or more; and/or c) address any reliability needs if the feeder contributes to poor SAIDI/ SAIFI metrics.

4.4 Timelines

The MA Tariff provides four different pathways to approval, based on the characteristics of the proposed DG process: Simplified, Expedited and Standard.[42] The MA Tariff had its origins in the multi-year work of the Massachusetts DG Collaborative, a multi-party stakeholder group that consisted of representatives of the DG industry, the utilities, state agencies and a variety of other stakeholders.[43]

The MA Tariff has been adopted by all investor-owned utilities operating in Massachusetts. The basic outlines of this process and the four pathways are summarized in Figures 1 and 2 of the MA Tariff which, along with the accompanying explanatory notes, have been extracted and reprinted in Appendix A. To set the stage for this section’s discussion of timelines, the “Maximum Timeframes” have been reprinted from Table 1 of the MA Tariff in Figure 4-5 below. Please note that these timelines are targets only. Failure to meet the timelines does not result in any penalty to the utility.[44]

[42] The Tariff also contains a fourth path, the Simplified Spot Network path. As neither survey respondents or utility commenters mentioned the Simplified Spot Network path, this study does not address that path.

[43] For a complete history of the DG Collaborative and copy of the initial Interconnection process as proposed in March 2003, see the “Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts” submitted by the DG Collaborative to MA DTE in Docket number 02-38-A.

[44] It is worth noting that, as per order of the MA Tariff, any complaints from customers are included in each utility’s quality service metrics.

Figure 4-5 Maximum Interconnection Timeframes

<table>
<tr><th>Review Step</th><th>Simplified</th><th>Expedited</th><th>Standard</th></tr>
<tr><td>Application receipt acknowledged</td><td>(3 days)</td><td>(3 days)</td><td>(3 days)</td></tr>
<tr><td>Application completeness review</td><td>10 days</td><td>10 days</td><td>10 days</td></tr>
<tr><td>Complete all screens and studies</td><td>10 days</td><td>25 days</td><td rowspan="2">125/150 days if an Expedited application is completed under the Standard process</td></tr>
<tr><td>Total maximum review period</td><td>15 days</td><td>40/60 days depending on whether Supplemental Review is required</td></tr>
</table>

The time frames in the MA Tariff do not include two categories of effort that take the time of applicants and utilities alike: the applicants' time in completing the application prior to submission, and the time of both applicant and utility in correspondence regarding information needed to fully complete and/or review the application. When the utilities encounter delays because customers have not provided information on which the review is dependent, the utility essentially suspends the time clock on the review period, pending receipt that information. The number of days spent in such 'process suspensions' has not been tracked or reported by the utilities and is therefore not analyzed in this review.

4.4.1 Current Experience

In this section we characterize the experience of both survey respondents and utility staff concerning the duration of the interconnection review process. We look first at the frequency of delays in the process, applicant satisfaction with the process duration over all then with individual steps in the process, and their expectation for how long the process should take. The reasons why the review period takes so long are discussed in the following section.

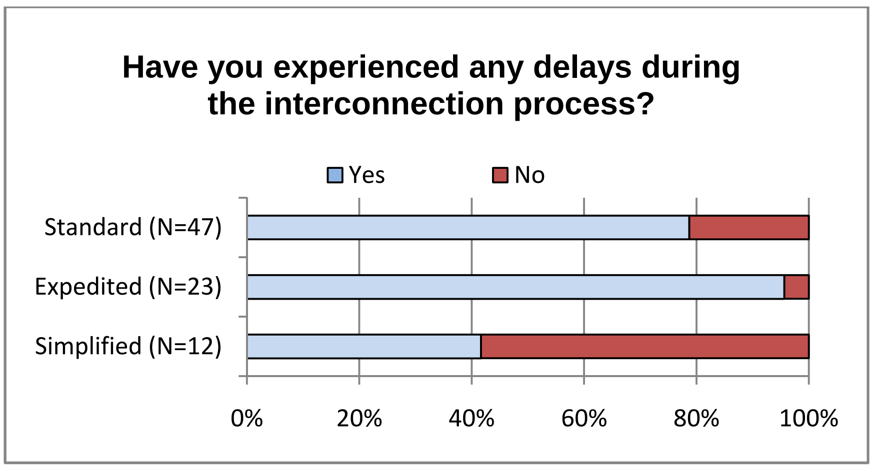
Among the most common complaints regarding the interconnection process is apparent inconsistency in the application of timelines in the MA Tariff. This leads to a widespread perception among applicants that the timeframes in the Tariff are just suggestions, have no teeth and that the length of project reviews will vary by project and utility. Representative comments include:

- "Every application in the Standard/ Expedited process has missed the deadline. There has been no transparency to the schedule either...."
- "I have had many applications go months beyond the published timelines. Also, the general tone and strive for meeting or beating the published timelines is non-existent."
- "If the standard was enforceable the timelines allotted are completely reasonable. The utilities consistently break the allotted timelines in spite of our timeliness in meeting their needs."

Overall, 72% of the 82 respondents answered "Yes" when asked whether they had experienced any delays during the interconnection process. As shown in

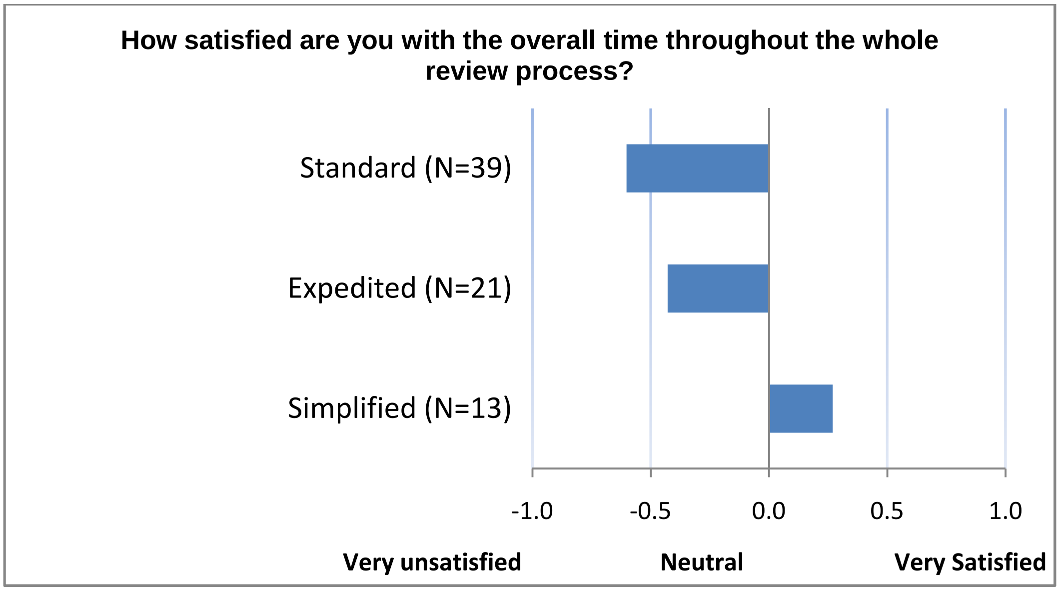
Figure 4-6 below, delays are most commonly experienced in the two non-Simplified processes; 58% of Simplified applicants received their approvals with no delays. By contrast, 92% of Expedited applicants experienced delays, as did 79% of Standard applicants.

Figure 4-6 Frequency of Delay in Interconnection Application Review



Simplified applicants are also satisfied with the total duration of the review process. As shown in Figure 4-7 below, Expedited and Standard applicants are also the least satisfied with the length of the review process, Standard applicants particularly so.

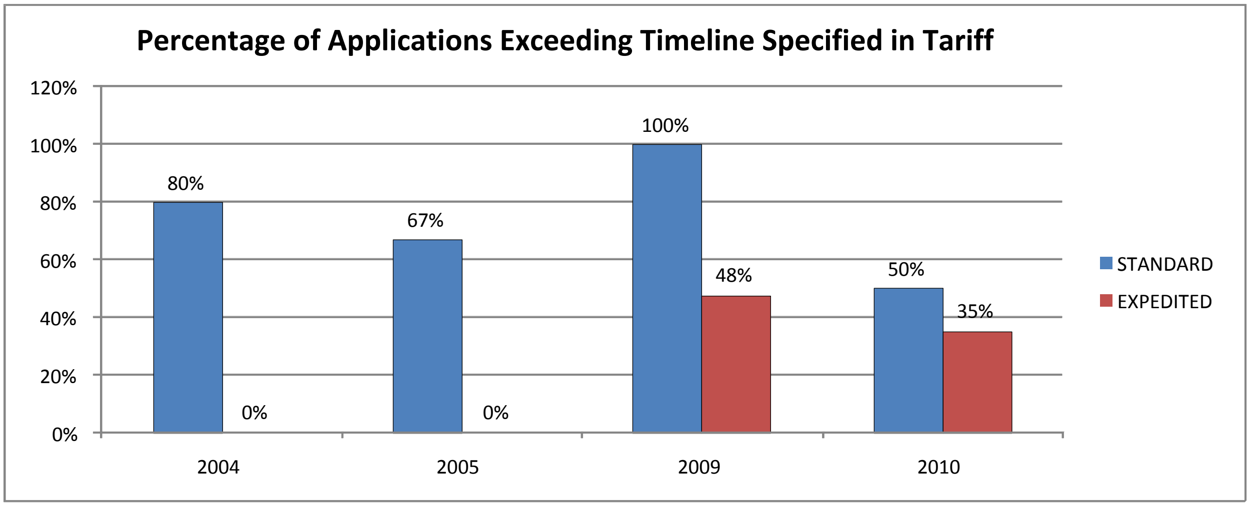
Figure 4-7 DG Applicant Satisfaction with Review Duration



We developed Figure 4-8 below from the utility tracking data. It shows that the majority of applications reviewed under the Expedited path are completed within the maximum timeframe. The more complex Standard applications, however, have posed a challenge. Progress has been made in 2010, as 50% of the Standard applications were reviewed within the timeframe. Over time, Standard applications have frequently exceeded the timeframe. Utility interviews examined the question of process delay by asking respondents to trace the timing required to review a ‘typical’ Standard application with which they were directly familiar. We then averaged the length of the review periods for these eight Standard examples. The average of these eight review periods, as cited by the reviewers who worked on each process, came to 50 weeks.

This average underscores a core finding of this report – current application tracking is too vague and inconsistent. Without data on the delay periods within each review process, it is not possible to determine the length of the review steps themselves. Nor is there any basis for determining the adequacy of any review standard. Utility respondents suggest that the maximum timeframes set for Standard view is insufficient, yet at this time, there is no data on which to basis the setting of any alternative guidelines.

Figure 4-8 DG Applications Exceeding Tariff Timelines



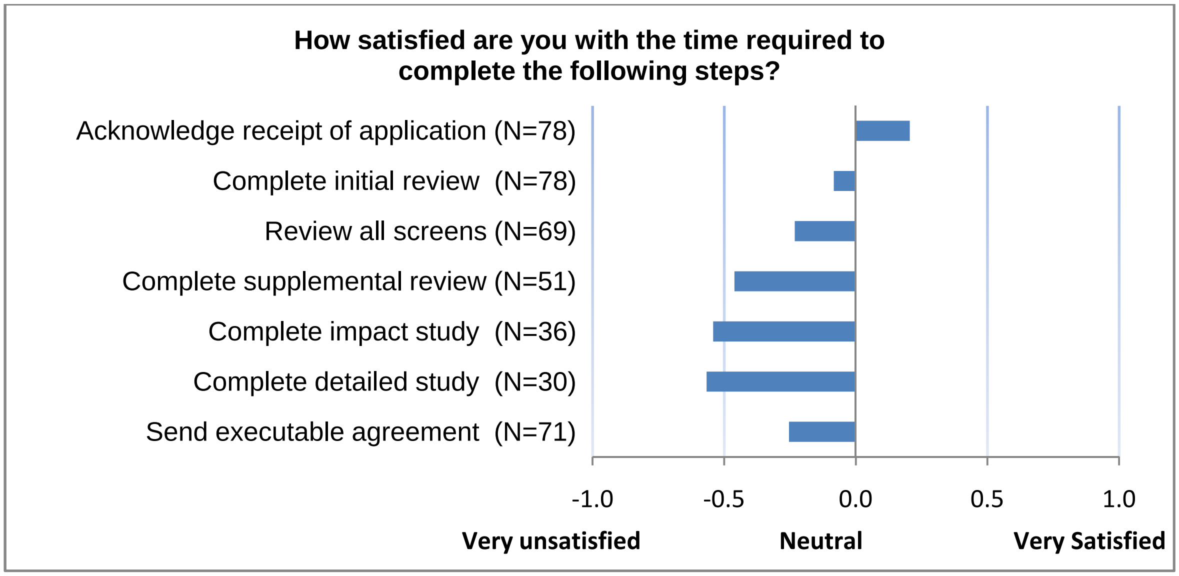
Reasons for the extended review periods are discussed further below. Before doing so, however, we offer the following caveats about the data shown on this chart:

- Figure 4-8 only tracks applications that have made it through the entire process to an interconnection agreement. 2010 results will therefore be higher than depicted due to applications not yet completed but already exceeding the 125 or 40 day timeline.

- As reported in Figure 4-1 through Figure 4-3 in Section 4.2, 2009 saw a substantial increase in the size of some DG projects submitted for review that year. A substantial portion of these larger projects were systems projecting an excess of generation over on-site load (including stand-alone net metering projects without a significant existing load). Projects of similar scale (>1MW) had been interconnected in other states but often at the transmission level, where in MA they are being integrated into the distribution system. Utilities report that significant learning took place on these projects, increasing time requirements in 2009 and reducing some time requirements in 2010.

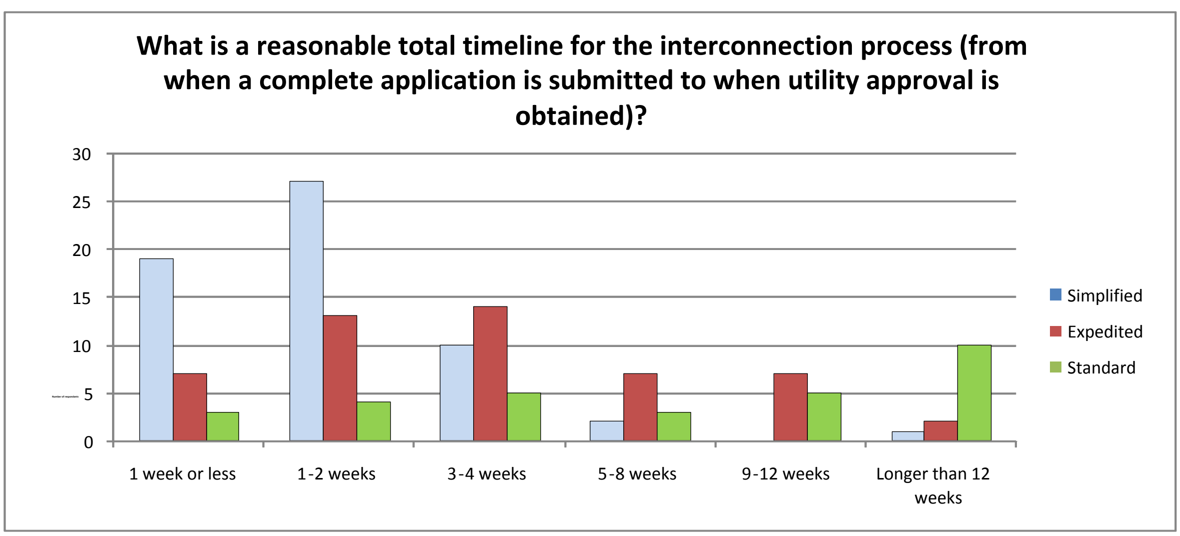
The industry survey asked about satisfaction with the specific steps in the review process. Figure 4-9 below summarizes overall applicant satisfaction with each of the seven review steps. Only the timeframe for acknowledging receipt of the application – three business days under the MA Tariff – received a favorable rating. Time to complete the detailed study, initial review, supplemental reviews and follow-on studies were all deemed unsatisfactory.

Figure 4-9 DG Applicant Satisfaction with Review Steps



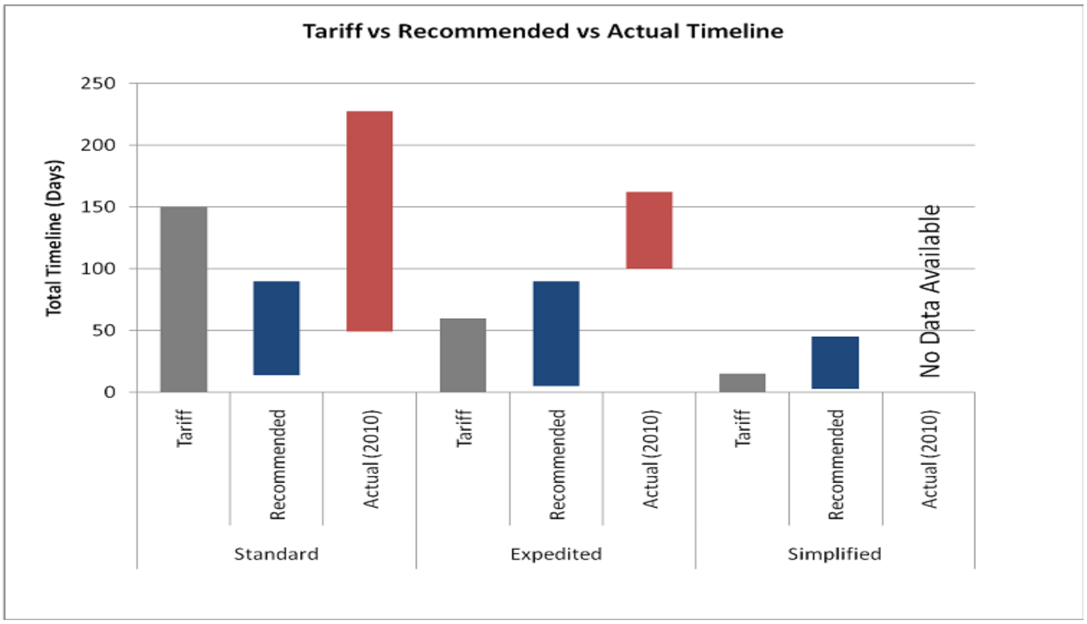
By contrast, Figure 4-10 summarizes the industry's expectations for a reasonable period of review, according to review pathway. The majority of applicants under the Simplified pathway expect a review period of two weeks; responses from the 59 respondents averaged to 15 days. Replies from the 50 Expedited respondents averaged 30 days, and from the 30 Standard path respondents, the average 'reasonable' duration was 62 days.

Figure 4-10 DG Applicants Expectations of Review Duration



To wrap up this review of process duration, Figure 4-11 below compares three ranges. For each of the three review paths, we juxtapose a) the maximum timeframe per the MA Tariff, based study requirements; b) the maximum and minimum times recommended by survey respondents, and c) the range of actual times in 2010.

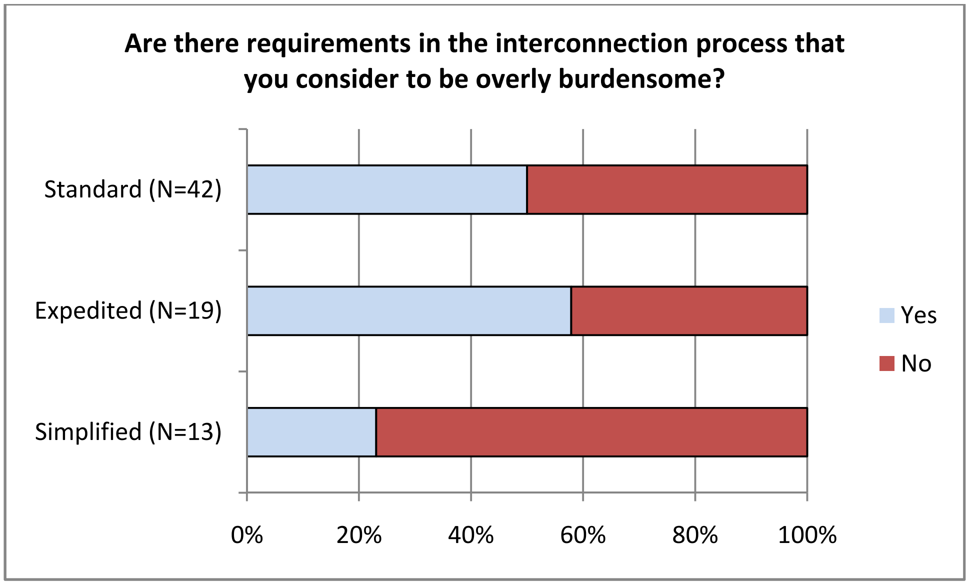
Figure 4-11 DG Application Review Times: Tariff, Actual and Ideal



Both the Standard and Expedited paths require significant improvement to realize the MA Tariff time frames. Significantly greater improvement in realizing outcomes will be required to meet industry needs.

In summary, almost half of the survey respondents reported that there are requirements in the interconnection process that they consider “overly burdensome”. This is particularly true for Standard and Expedited applicants. True to the pattern of our responses, however, only 22% of Simplified respondents found anything burdensome about the process.

Figure 4-12 DG Industry Views of Interconnection Process



Many respondents said that time delays are the main burdens (discussed in the next section) followed by cost and the lack of transparency. Commenters mentioned both administrative and technical ‘burdens’, as these vary by path. Standard applicants frequently mentioned paperwork, all with time-consuming required sign-offs. Others perceive it redundant to require both an impact study and detailed study. For technical requirements, some perceive that requirements for external disconnect and protective relays are unnecessary and overly burdensome. These will be discussed in further detail in the following sections.

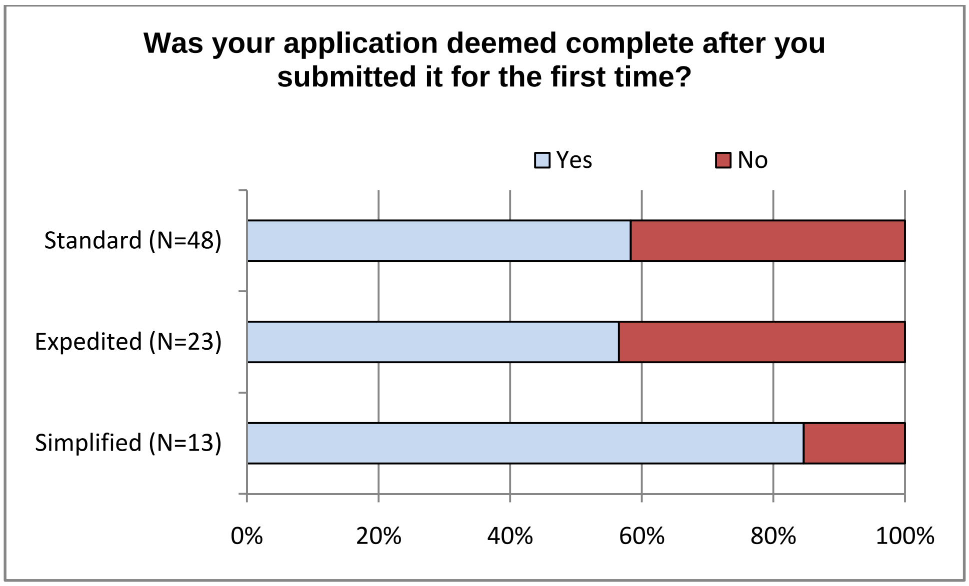
4.4.2 Causes of Interconnection Process Delay

The survey asked DG applicants a number of questions about their experience during the interconnection review process. Overall, 72% of the 89 survey respondents had experienced some kind of a delay during this process. Simplified applicants experienced the least delay, as over half of Simplified applications were approved without delays. Applicants seeking review as Expedited projects reported the most delay, with 96% of these reporting a process delay. 70% of the Standard applicants reported delays, while 19% reported no delay and 11% did not respond to the question. In the following sections, applicant perspectives are explored first, followed by utility perspectives. Further detail on the experience of applicants in each of the review pathways is provided in the next section.

Applicant perspectives

Incomplete applications. A major reason for delay arises when applicants do not submit a complete application. This results in extended "completeness review" and multiple submittals. While this is not a big issue with the Simplified process, for the Standard and Expedited process, over 42% of the survey respondents reported that their application was not deemed completed after their first submittal.

Figure 4-13 DG Interconnection Application Completion

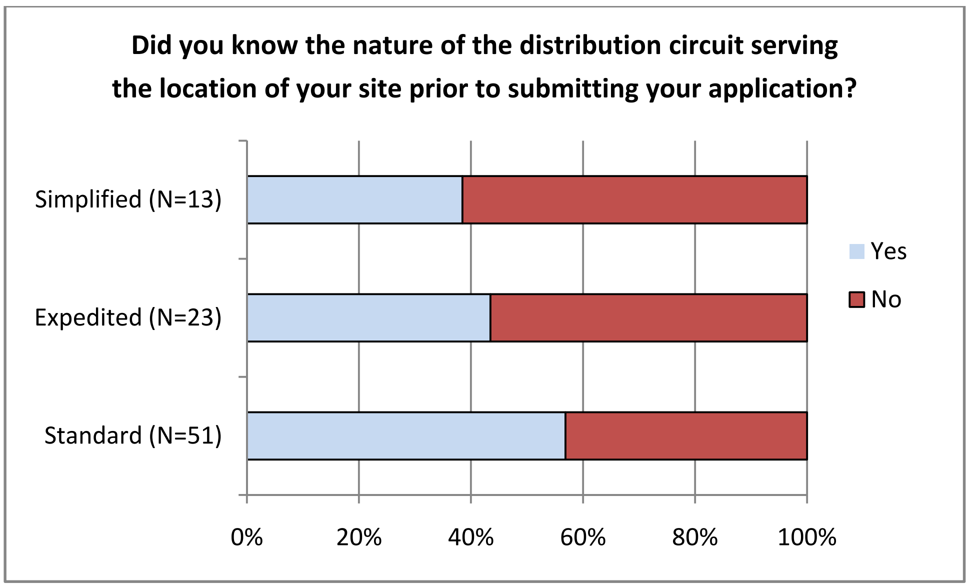


For Expedited and Standard processes, interconnection application requires significant technical detail on proposed DG equipment before the application is accepted as "complete". Most commenters had to resubmit the application or supplemental materials once or twice; and a few respondents three or four times. Some applicants were asked to provide information not required in the original application, such as the project schedule. Some applicants were asked for technical information not available at the time of application. For example, equipment is usually not procured before the time of application, but the information is required on the application. Developers and installers find this requirement unnecessary; even if they have the equipment information is available at the time of application, the final equipment may change due to availability, forcing a change in the application.

Other discrepancies reported by survey respondents include the threshold for interconnection procedures[45], requirements for the redundancy in protective relaying schemes, interpretation of equipment standards, and requirements for exterior disconnect and witness tests. In addition, the protection schemes could change from project to project depending upon the specific utility engineer responsible for the review.

Information on utility distribution circuits An understanding of the utility's distribution circuits can enable developers to better site DG in areas where interconnection will be less expensive. However, when survey participants were asked whether they knew the nature of the distribution circuit serving their site prior to submitting their interconnection application, almost half of the DG respondents (49%) answered "No". Not surprisingly, this is more prevalent among those who have only had experience in the Simplified process or the Expedited process.

Figure 4-14 Pre-Application Views of Circuit Type

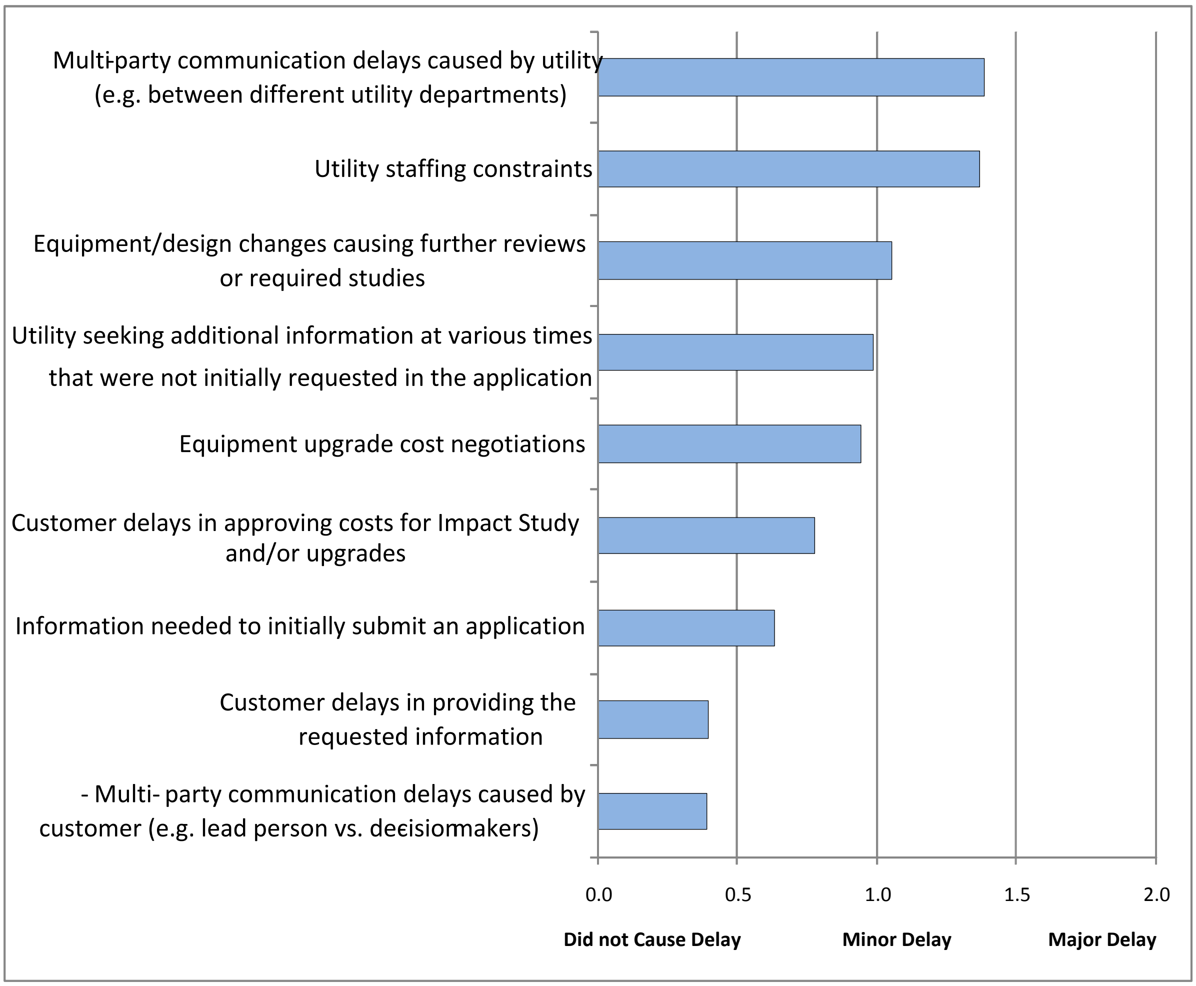


Most installers or developers request this information from the utility. Some respondents report driving around the field to observe labels on transformers. Others hired engineering firms or consultants to determine the nature of the distribution circuit by conducting detailed feasibility study.

[45] One respondent said that for systems in the size category < 25 kW with multiple single phase inverters on a 3 phase network, there is inconsistency in the applicable procedures, i.e., sometimes they get approved for the Simplified procedure and sometimes not. The comment did not provide any insight into the basis for these inconsistencies.

Figure 4-15 summarizes the most common causes of delay reported by DG applicants. The two most frequent delays observed by applicants are a) multi-party communications delays caused by the utility, essentially tied with b) utility staffing constraints. These two leading causes were followed in importance by changes in equipment or design that triggered further review or studies; the utility's requests for additional information and negotiations about equipment upgrade costs.

Figure 4-15 Interconnection Process Delay: Applicant Perspective



In their responses, industry applicants did acknowledge to some extent the delay attributable to their own actions, i.e., either incomplete applications or delays in providing information to the utilities mid-process. Survey respondents also gave a very weak endorsement to the current policy allowing the utility to restart their interconnection process and waiting period in response to significant applicant delays (48% agreed, 44% disagreed, with 8% not answering).

Overall, the survey questions about process delays elicited a significant amount of comment from survey respondents. A categorization of these comments found some commonality, for example around slow initial review steps, staffing issues, lost applications and the challenges of scheduling witness tests in a timely manner. Perhaps more interesting, however, was the extent to which comments from survey respondents revealed areas of misunderstanding and/or misplaced expectations between the DG applicants and the utility industry. These gaps in understanding highlight the dynamic nature of DG's impact on the distribution system in general and the individual circuits in specific:

- DG's impact on feeders – Installation of DG on a circuit can significantly change the performance characteristics of that circuit. Commenters that contrast the costs and timing of a project (e.g., "….a year ago in the same location…." with the "….completely new requirements mandated today….") may feel that they are indicting the utility for inconsistency. More likely, they have failed to understand that, to the utility planners, that feeder is now different – by virtue of the previous project — than it was a year ago.

- Smart Grid penetration – Several commenters pointed to the advent of bi-directional Smart grid controls and distribution automation systems as eliminating the rationale for applications to bear the cost of bi-directional change-outs on circuits affected by their project. Regrettably, DG projects seeking to interconnect prior to the installation of such Smart Grid devices on the specific circuit they have targeted will, under current cost allocation policies, have to bear the cost of the modifications their DG requires. Sections 7 and 8 discuss possible steps to improve the information available to applicants on Smart Grid penetration and other aspects of "DG Readiness".

Utility Perspective

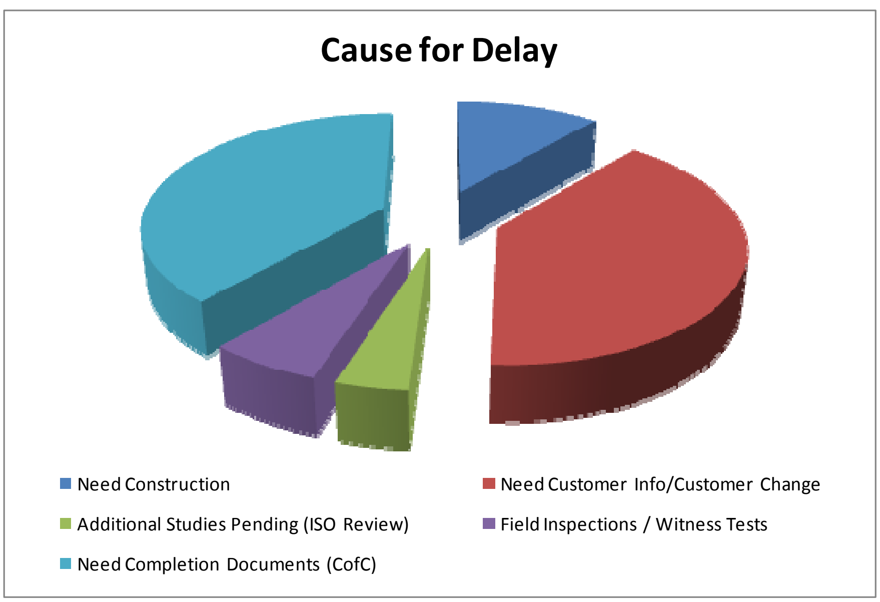
The tracking data sets described in Section 4.1 contained additional utility comments regarding the source of process delays. KEMA categorized this comment into the categories listed below and depicted in Figure 4-15.[46] These categories are explained as follows:

[46] Withdrawn, cancelled and completed applications were excluded.

- Customer Information or Design Change Required – Utility comments frequently identified delays due to waits for customer information. This information may reflect information requested after the application, additional detail on design changes, and/or other information needs that arose during the process.
- Completion of Documents – This category includes those applications for which the utility is waiting on the completion of documents by the applicant or other non-utility party. This includes the Certificate of Completion.
- Additional Study Pending **–** These comments indicated the utility's need for additional study and a consequent delay in the application process. Also included in are interconnections requiring study and review by the ISO.
- Construction Needed – Both the customer and the utility must complete any project- or interconnection-related construction before the project can be commissioned. This category covers delays both utility and customer delay related to the cost and/or timing of the additional system upgrades required prior to interconnection.
- Field Inspections/Witness Testing **–** This category includes comments pertaining to waiting on field inspection or witness testing to complete the application process.

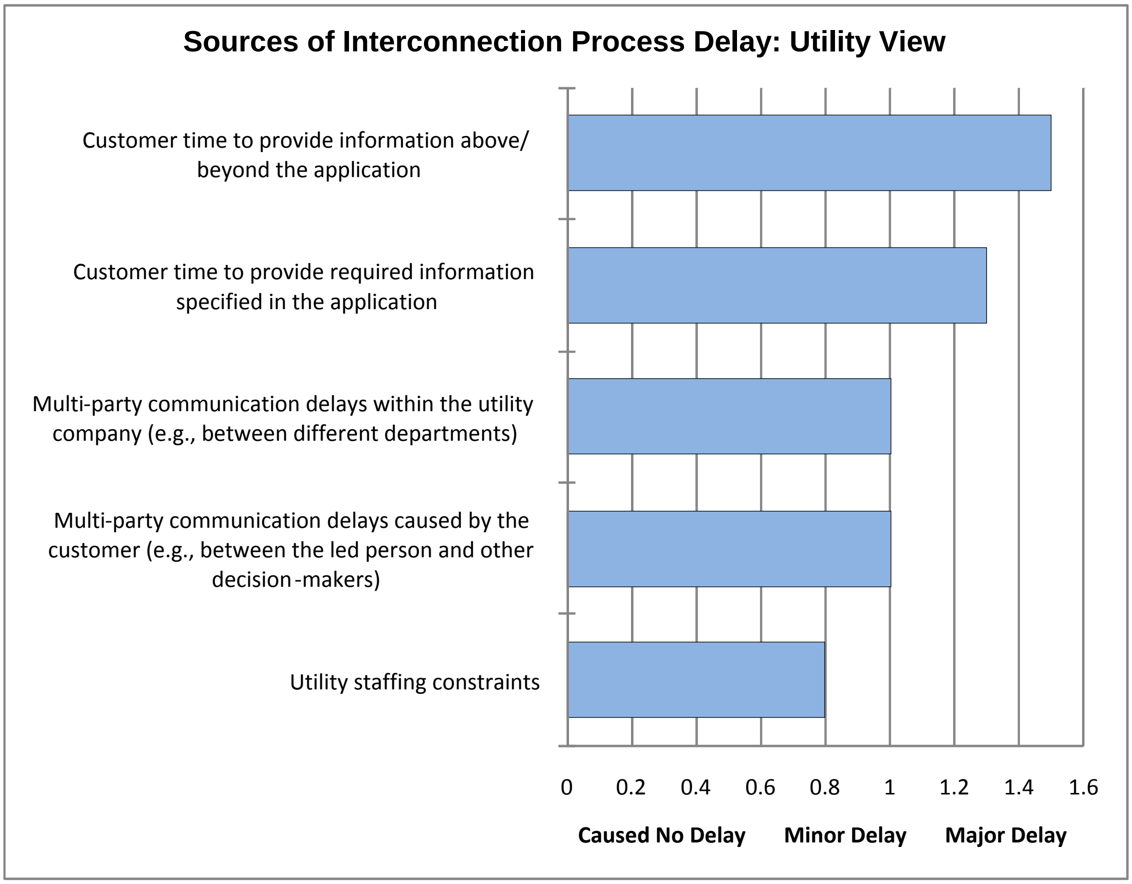
As shown in Figure 4-16, these utility comments suggest two main categories of significant delay: construction-related delays and customer-dependent information-related delays.

Figure 4-16 Delay in DG Interconnection Application Review: Utility View



KEMA's utility interviews enabled us to gather utility perspective on several questions asked of survey respondents. Figure 4-17 below confirms the finding from the tracking analysis: utilities perceive that customer-related delays are the most frequent reason the review process exceeds its targeted duration.

Figure 4-17 Sources of Interconnection Process Delay: Utility View



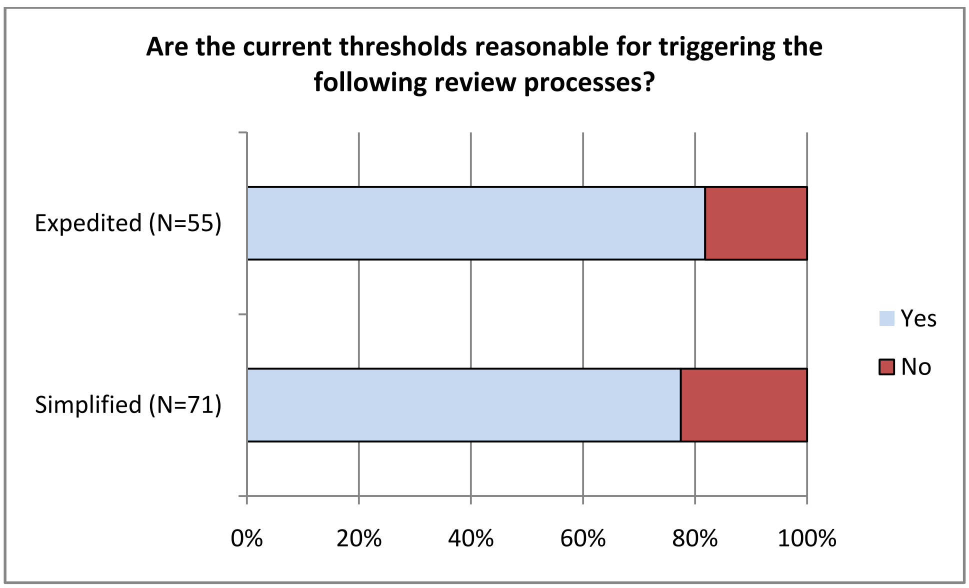
Not surprisingly, both the utilities and the applicants see each other as the primary source of process delay. Under the present tracking process, there is no tracking or recording of the length of mid-process delays. Without data on the length of delays, it is not possible to calculate 'corrected' total elapsed duration for these average review periods. The inability to track process "stops" – regardless of cause – and therefore to objectively account for the total duration of the review process is a significant flaw of the current process.

These differing perspectives underscore the need for a tracking process that is fully transparent and objective. Performance metrics must be tied to milestones that are clearly defined and consistently applied. These metrics must not be subject to suspension unless the rules for doing so are also clear and transparent.

4.4.3 Sources of Delay by Path

The three approval paths under the MA Tariff have different requirements for both applicants and reviewers. In this section we examine applicant and utility experience by path, with particular attention to three factors: a) the completeness of information in the initial application; b) the need for additional information midstream; and c) application of the screens.

Figure 4-18 DG Industry Views of Interconnection Thresholds



Currently, the "Simplified" process applies to a) Single phase customers with listed single-phase inverter based systems 10 KW or less on radial feed; b) Three phase customers with listed three-phase inverter based systems 25 KW or less on radial feed; and c) Under some circumstances, a single phase inverter on a spot network system 15 KW or less may be eligible. For projects to qualify for Expedited process, the facilities must pass certain pre-specified screens on a radial electric power system.

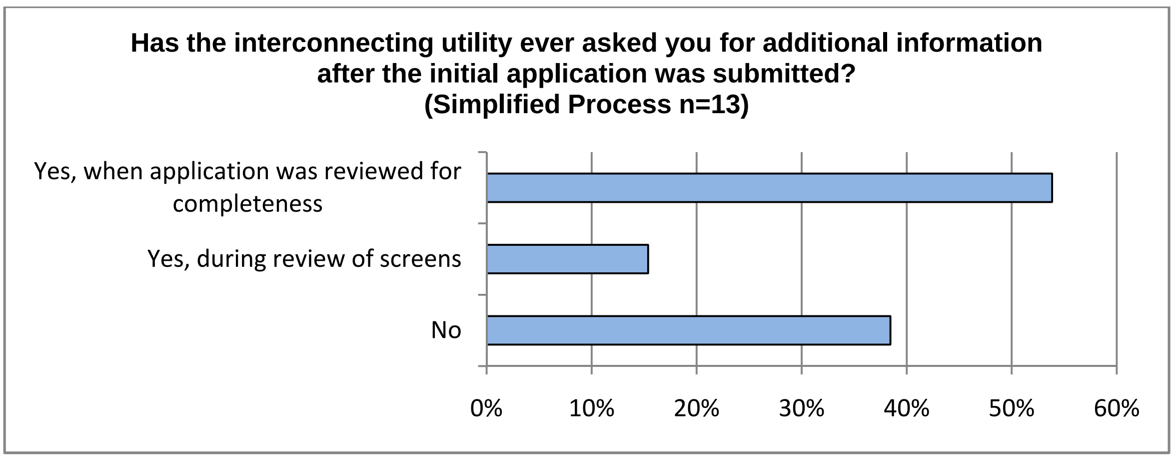
As shown in Figure 4-18 above, most survey respondents find that the current thresholds for triggering either the Simplified or the Expedited process are reasonable. Even so, there is room for improvement for both of these processes. These are discussed next.

Simplified Path

As shown previously, those applicants following the Simplified path generally do not express the same levels of frustration voiced by other applicants. Figure 4-7 shows that applicants are generally satisfied with the total time required for Simplified review. 85% of Simplified applicants were able to submit an application that was deemed complete on the first try. This compares to 58% of applicants overall.

At the same time, 58% of Simplified applicants did experience delays in the review process (also shown in Figure 4-6). As shown in Figure 4-19 below, 69% of these respondents replied that they had been asked for additional information after the application was submitted. In 54% of these cases, the request was made during the application completeness review.

Figure 4-19 Post-Application Information Requested: Simplified Path



Applicant comments suggest that "there is enough experience that the thresholds could be raised safely for Simplified". For the Simplified process, many respondents suggested that the threshold could be increased. The suggested levels span a wide spectrum, but in general, an increase to 30kW for single phase and 100 kW to three-phase is a common recommendation.

Utility comments agree in some areas. Utility respondents find the screens simple, useful and direct to apply, and resulting in clear, unambiguous yes/no or pass/fail determinations. If any uncertainty arises in the screen tests, the reviewer will refer to a group manager or the internal engineering department. Two of the utilities volunteered that, where a project change would enable the project to pass a screen, they will call the applicant to discuss that modification.

In general, the utility respondents view the current screens as working well and protective of adequate margins of system safety. They are therefore very reluctant to pursue any changes to current screens. Individual respondents did identify a few areas where discussion of possible changes to screens might be appropriate:

- 7.5% of aggregate peak load – three suggestions were made on this point:
    - The requirement should target "minimum" load, not peak load;
    - A PV-specific requirement should examine minimum load in the "shoulder seasons" of April and October; and
    - For inverter-based DG and in cases of single-phase interconnection on a single-phase transformer, it might be possible to increase the limit above 7.5%.
- The Facility Power Rating of < 10KW – possible conditions under which it might be possible to increase this limit include:
    - Single-phase DG on single-phase line;
    - DG output is less than on-site load;
    - No other DG exists on the line;
    - DG is inverter-based with single inverter only; and
    - DG is behind the meter.

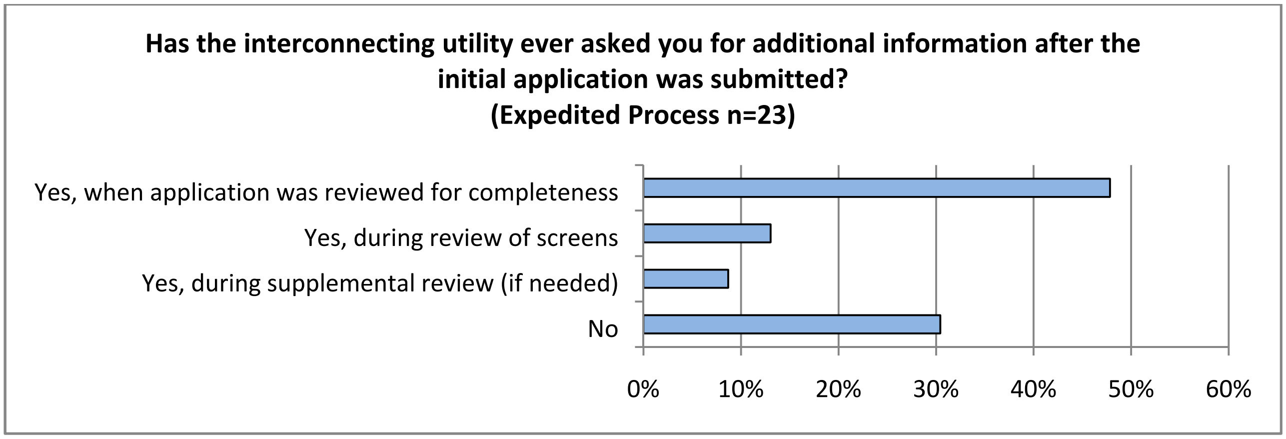
Any screen modifications would have the intention of enabling more applications to be handled as either Simplified or Expedited, therefore simplifying and speeding the review. For any and all of these potential changes to receive due consideration, however, utility respondents pointed out that a statewide process is required. Such a process ensures that all potential considerations and concerns have been appropriately aired and addressed.

Expedited Path

Referring again to Figure 4-6 above, Expedited applicants are the most likely to experience delays in the process. 48% of the Expedited respondents considered some portion of the process 'burdensome". 43% of Expedited applicants were not able to submit a fully- complete application on the first try. This may be attributable in part to the fact that 57% of this group reported that they did not know the nature of the circuit to which they wished to interconnect at the time of their application. In contrast, 55% of Standard applicants did have and were able to provide this information.

70% of Expedited applicants report having been requested to provide additional information, as shown below in Figure 4-20. In 48% of these cases, the request was made during the completeness review.

Figure 4-20 Post-Application Information Requested: Expedited Path



Like the applicants following the Simplified path, 82% of survey respondents agreed that thresholds for Expedited review were reasonable. Those who did not find it reasonable did not offer any common recommendations.[47] Survey comments suggest surprise among applicants when, during the review process, the utility treated their application differently than they either expected or had experienced in another situation. Better attendance at the interconnection workshops might help, as attendees would hear discussion of the decision criteria associated with each of the screens, and the range of possible project upgrades and/or system modifications likely when the screen is failed.

The utilities have different experience regarding the fraction of Expedited applicants that fail to pass one or more of the screens, and thereby finish the process under the Standard path. Keeping in mind that the utilities receive very different numbers of Expedited applications (from 0 to 190 in 2010), the utility interviewees reported that an average of 20% of Expedited applications in that year failed one or more of the screens and was therefore reviewed under the

[47] One respondent said "less than 201 kW" and another said that based building load should be taken into account.

Standard procedure. As one utility commenter pointed out, "They (DG applicants) don't understand that it's NOT their choice whether they are Expedited or not."

The fourteen Expedited applicants responding to the survey reported the system impacts summarized in Table 4-2 below (respondents were able to indicate multiple impacts).

Table 4-2 Impacts Noted by Utility Review: Expedited Path

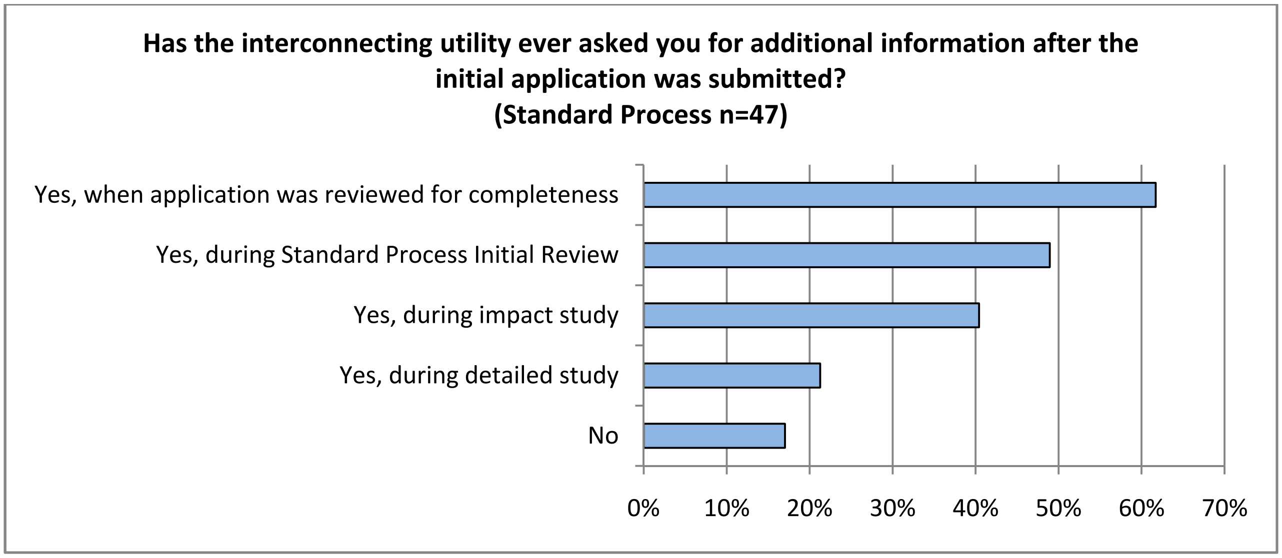
Impacts Noted by Utility Review	n=14
Over or under voltage	29%
Frequency control (including harmonics)	29%
Reverse power protection	21%
Fault protection	21%
Impact on the grid from loads occurring from a breaker trip	14%

Standard Path

As discussed earlier, the Standard process is the most complex and the longest in duration by months. Completion of the required review steps requires considerable sharing of information between the utility and the applicant. In the Standard path, only 17% of applicants have NOT had to provide some type of additional information for use in the application review process. As shown below in Figure 4-21, 62% of Standard applicants were asked for additional information as part of the initial application completeness review.

This question allowed respondents to indicate multiple responses as appropriate; the chart shows that respondents were frequently asked for additional information during more than one step in the process. In reply to a separate question, 28% of Standard applicants report being asked to provide data for the utility to use in its modeling.

Figure 4-21 Post-Application Information Requested: Standard Path



Standard project applicants report that the utility noted a variety of impacts attributable to these larger and likely more complex projects. As shown in Table 4-3 below, the most common impacts are over- and/or under-voltage concerns, reverse power protection and fault protection.

Table 4-3 Impacts Noted by Utility Review: Standard Path

Impacts Noted by Utility Review	N=35
Over- or under-voltage	46%
Reverse power protection	43%
Fault protection	40%
Impact on the grid from loads occurring from a breaker trip	37%
Frequency control (including harmonics)	34%

Standard projects are those that do not pass the technical screens characterizing situations with known parameters and for which the utilities can design a protection regime that adequately ensures system reliability for all interconnected customers. Outside the boundaries of the screens, the utility planners enter operational territory that is less familiar, less predictable and therefore requires more study and potentially more design to ensure adequate margins of safety.

As the rate of DG applications continues to increase, DG planners look ahead into additional unknown territory. Much of their concern is related to the interactive affects of multiple DG installations on a single feeder or circuit. Comments on this point included:

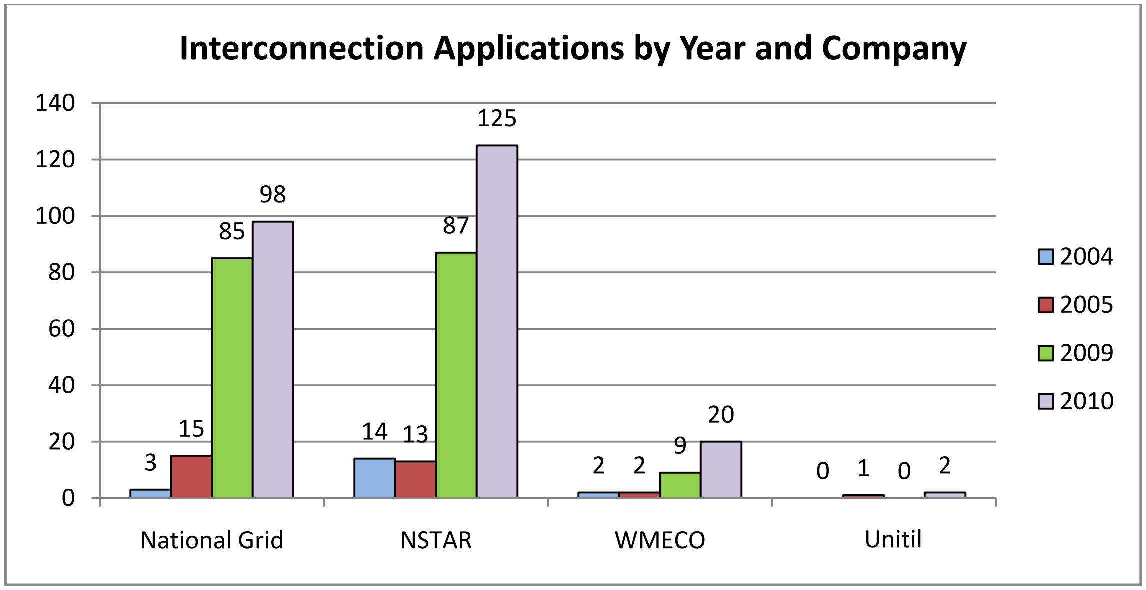
- “Don’t change anything. I’m worried that the interactions between units might not be caught. A database is kept of where DG is located….”
- “Our concerns are applications that use multiple inverters – in the screens … the thresholds are set up to give the utility a comfort level for safe operation. When there are multiple inverters on the project, I lose that comfort level. This is because all the testing and operational history to date on all inverter systems has been done with systems tested as individual units….”
- “In my view, the screens are working well, however something we didn’t anticipate was the use of multiple inverters. If the system uses a single inverter, the project could be 20-25 kW for single-phase....”

The comments of Standard applicants reveal their desire for more transparency in the decision criteria behind the published screens. They also seek, as do Expedited applicants as well, a better understanding of the translation between the screens and the resulting upgrade requirements. These are reasonable requests. Yet the ability of utility planners to satisfy those requests and be transparent in their decision rationales is constrained in circumstances that pose many unknowns.

4.5 Application Volume

A key if not surprising finding from this analysis has been the growth in the total volume of DG applications received by the IOUs. As shown in Figure 4-22 below, the total number of applications has increased dramatically from 2004-05 to 2009-10. For National Grid and NSTAR, the total number of applications increased by more than four-fold in just 5 years.

Figure 4-22 DG Expedited and Standard Applications 2005-2010 by Company and Year



The following charts illustrate clearly the challenge of the current interconnection process. As the volume, size and complexity of the applying DG projects continues to grow, so too does the complexity of the required utility review. The trajectory is clear – with the rapidly growing number of applications being submitted each year, the completion gap is growing.[48] These charts suggest that National Grid, NSTAR and WMECo appear to have reached – by 2009 – a maximum number of applications they can process annually. Only Unitil with its much smaller number of total DG applications per year has been able to keep pace with the demand.

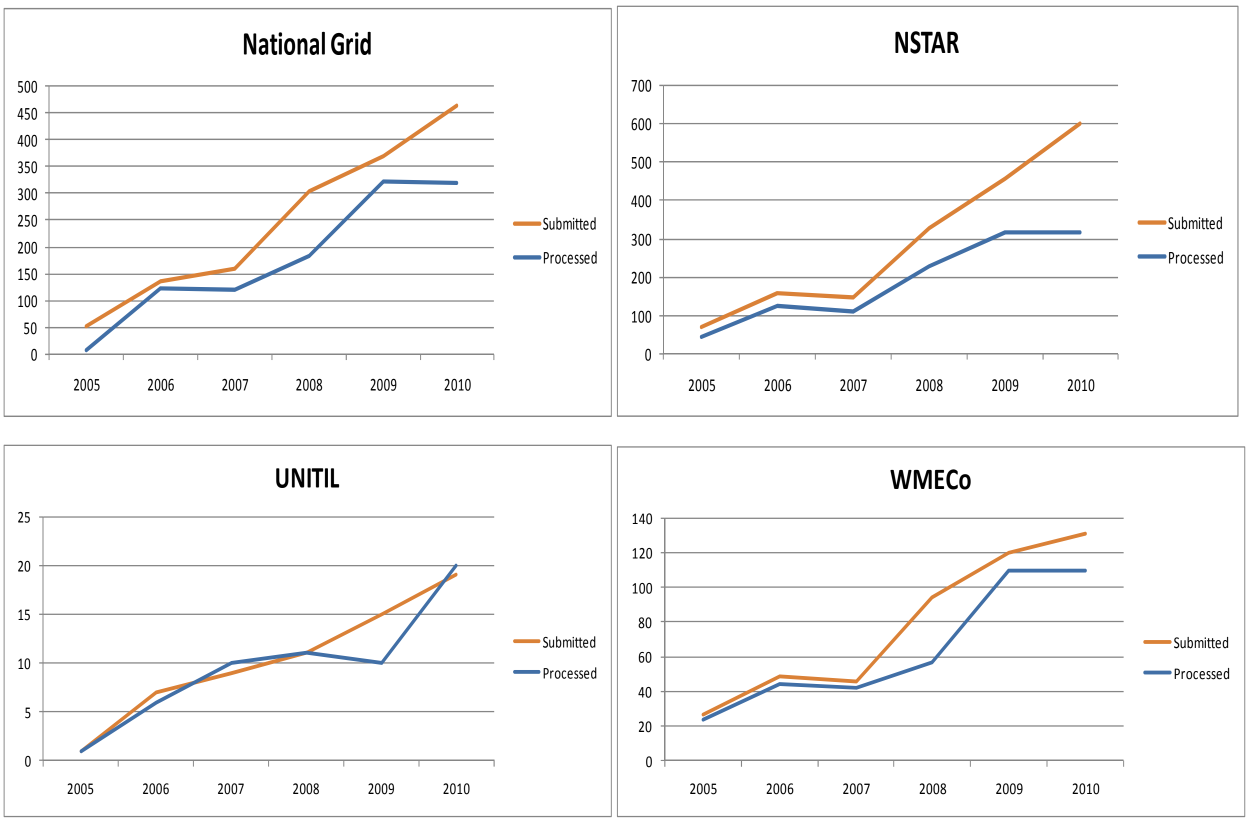
We offer several observations from this pattern:

- Additional engineering resources may be necessary for the utilities' to maintain pace with the number and growing complexity of applications being submitted.
- The growing penetration of large projects, particularly those planning to export power, adds complexity to the system modeling upon which the DG review and approval process depends.
- These figures may reflect difficulty granting interconnections as DG penetration increases in different parts of the distribution system. The more DG is interconnected in a circuit, the more difficult it is to model the effects of additional DG.

[48] Data Source: DPU 11-11 Attachment A IR Summary.xls

- The current infrastructure may have difficulty accommodating additional DG interconnections in some areas without significant system upgrades.

Figure 4-23 DG Applications Submitted vs. Processed Each Year



The trends toward continuing volume growth and increasing project complexity, particularly in the Standard process, suggest that leaps in productivity and accompanying process redesigns are going to be essential. The alternative is an increasing level of backlog and delay in the interconnection of new DG. Major process changes and/or significant additional resources will be required to meet the timelines of the present MA Tariff. These are discussed further in Section 8.0.

4.6 Discussion of Potential Solutions

This section is divided into two parts. We begin with a summary of the observations and key points introduced above. For each major point, we then discuss possible actions to address the issues identified herein. We note, however, that the approaches discussed are not final recommendations; rather they are conceptual approaches and suggestions. As such, they are intended to provoke further exploration, discussion and debate, likely in either a collaborative setting or within an appropriate forum created by the DPU or DOER, as shown in the Recommendations, Section 8.0.

4.6.1 Observations of the Review Process

Key observations based on this review include:

The interconnection review process works well for some, not well for others. Applicants with smaller, simple systems are satisfied. All others find the process burdensome, inconsistent and much too long. Expedited applicants are most unclear about the requirements, yet these are the beneficiaries of the "expedited", screen-driven and thereby potentially shorter review. Standard applicants, with the largest projects and most complex review processes, have better understanding of the rationale behind the required studies but still seek more expeditious completion.

An interconnection crisis is near. The volume of DG applications has grown substantially since 2009 and is expected to continue growing under current policy. At the same time, interconnection completion rates have plateaued. Data summarized in this section shows that three of the four utilities are no longer able to keep up with the rate of DG applications.

Timeline tracking is not working and accountability needs improvement. Tracking data available for this study represented a mix of inconsistent time periods, application types and other data inconsistencies. With no data on the periods during which reviews have been suspended, it is not possible to determine the average duration of review steps. While review timelines for Simplified applicants are largely met, review timelines for Expedited and Standard applications are met far less often.

Interconnection applications are frequently incomplete. A vicious circle exists with regard to the submission of information prerequisite to a timely application review. Utilities frequently don't get what they need from applicants; they request additional information in at the beginning and during the review process. At the same time, applicants can't learn what information they need to complete their application package, until they apply.

The rate of review completion needs to increase significantly. Data on the growth in applications versus the rate of interconnection approvals supports the DG industry's claim that the interconnection process is constraining industry growth. As the backlog of projects awaiting review and/or the length of time spent in review continues to increase, this problem will grow. A complete “re-engineering” of the current system is warranted. This re-engineering should examine the current process from several vantage points:

- Removal of process inefficiencies – Our analysis identified several areas where the current process loses time: shortfalls in applicant understanding; lack of information pre-application; submittal of incomplete applications; communications issues during review; delays due to study costs and associated approvals; all in addition to the time associated with the required studies themselves.
- Increasing the throughput of existing steps – Applicants and utility staff agree that some existing screens can be reexamined and possibly modified. Increasing the scope of existing screens and identifying new screens, e.g. to differentiate projects on the basis of generator type (inverter-based, synchronous, induction).
- Isolating the ‘truly new’ – Utilities rightfully worry about the system impacts of larger and more complex DG projects; multi-inverter projects; the interactive effects of successive DG on feeders (and especially in networks); synchronous new technologies. For projects that are truly ‘new’, review timelines and associated penalties would not apply.
- Enforcing timeline targets – With no ‘teeth’ to the current timelines, utilities may not be as motivated as the industry would like, to examine their own processes and invest in tools, personnel and/or other process changes that could improve review times. The re-engineered process should result in clear process tracking, including for any suspensions of the review process, and an overall “On-Time Completion” metric for each utility.

4.6.2 Potential Action Steps

The following suggestions fall under the general headings of timelines, application submittal and review, and costs.

Timelines

The 2006 Report of the DG Collaborative concluded that “Further tracking of the timeline for units is not necessary. No complaints about the timelines for the studies have been received by the utilities."[49] We submit that DG's growth over the last five years requires reexamination of both statements in 2011.

- Resume utility timeline tracking – As long as the current Tariff timelines remain in effect, utility tracking of process timelines and milestones is warranted. Such data provides the only data with which to objectively examine the rate of interconnection approvals and trends in the duration of the process steps. DPU and DOER have agreed to reinstitute monthly reporting; while some utility reporting data has been submitted, the format of these monthly reports is unresolved as of the date of this report.
- Track the entire process – Applicants experience the interconnection process in its entirety, from the time of application through system operation. Each step of this process should be tracked; doing so will – in time – enable the industry to make accurate projections of construction and interconnection timing, to aid both developers and their investors. The 'entire process' includes project construction, the installation of interconnection equipment and related protection as well as the final inspection and commissioning steps.
- Create rules for suspensions of time tracking – The utilities suspend the MA Tariff time clock for applicant delays in providing requested information. They do not, however, calculate or report the corrected duration of the review period, net of these time clock suspensions. As a result, the current data on process duration has little value. Without more accurate metrics on the true length of these review steps, regulators cannot judge the adequacy of the MA Tariff's suggested time lines. Better tracking, metrics and performance against the suggested time lines requires clear rules for both suspending the time clock and reporting those suspensions.
- Consider utility penalties – Applicants pay a significant penalty in the form of project delays when review timelines slip. Once the project application package has been accepted as complete, utility-caused process delays should carry a penalty to the utility. Funds collected as penalties should be earmarked to the support of DG-related applicant outreach and education.

[49] DG Collaborative 2006 Annual Report, page 32.

Application Submittal

A different system of application is required, one that matches the information requested of applicants more precisely to the needs of the specific level of review for which they have applied. Among other features of a revamped process need to be:

- Improved Interconnection Workshops – Develop an "Advanced" Interconnection workshop, for consultants and developers. Consider making attendance for the Advanced level mandatory prior to submission of proposing projects likely to be FERC-jurisdictional and/or receive Standard review.
- Posted distribution system information – Password protected and possibly available to applicants only upon completion of a workshop, this information could include a) a map of areas served by different types of circuits; b) location of relevant substations, transformers and relevant protective equipment; c) location of FERC-jurisdictional lines; d) location and size of existing DG, e) type and location of Smart Grid /upgraded devices/ lines; and f) color-coding re: application review steps triggered by different DG sizes/types (e.g., inverter-based vs. induction/ synchronous motors) in these areas.
- Site-specific application requirements – Based on the above information, applicants should be able to enter an address to learn the essential characteristics of their selected site. By entering information on the nature of their proposed project, applicants should also be provided with a list of the information that will be needed to fully support their application, through all of the likely review steps.[50]
- Pre-Application Scoping Meeting – Recommended for all applicants; mandatory for the most complex applications (e.g., by size; location per map) unless utility-specified criteria/ conditions are met (as described in later sections).
- On-line applications – Set the objective of eliminating 100% of the delays and information requests that currently occur during Completeness review. Electronic submissions give the ability to ensure that all required information is provided at the beginning; incomplete applications are not accepted for submittal. Electronic submittal with an internal system of file-sharing ensures that all utility personnel have easy access

[50] These two steps follow the lead of New York City's "100 Days of Solar", a Solar America initiative of the City and ConEd, under which NYC's 90-step permitting process has received a complete reexamination. See "Solar Approvals Simplified" in Solar Today, May2011, at http://solartoday-digital/solartoday/201105/?pg=46#pg42

to the same documents. Such a system could significantly improve intra-utility communications, one of the top causes of process delay.

- Phased application process – Design the electronic application to require information appropriate to the exact nature of the application, by path (Simple, Expedited, Standard); DG type, size, other system characteristics (via pop-up menus in the application) and location-specific requirements.
- Application time windows – For each application phase, the applicant will have a posted period (e.g., 5 business days) within which to submit 100% of the information required by the application tool for their application, with incomplete applications terminated at the end of that period. Applicants can open a new application when they have the required information ready for submittal.

Application Review

- Clear decision standards – Clear information prior to application is essential for the complete submissions. Utilities should publish the criteria, definitions and best/worst case requirements for key elements of the review process. Specific definitions/ criteria to be provided include the following; published information should also specify the degrees of freedom the utility will exercise in determining whether or not a specific requirement will apply:
    - What conditions trigger the requirement for additional upgrades such as protective relays or other protection/ protective devices;
    - When are external disconnect switches required or not required;
    - When are witness tests required or not required; and
    - What are the technical ranges around critical dimensions of equipment performance – such that, if equipment changes do occur between application and the end of the review cycle, the components are deemed sufficiently equivalent that the review may proceed on the same basis.
- Current application screens – All existing screens for both Simplified and Expedited paths should be reexamined, to see whether current limits can be enlarged based on the accumulating base of experience. Vermont's recent enactment of a solar registration law minimizes the process still further for small PV. Under this statewide law, utilities have 10 days after the homeowner has registered the intended system to raise any

interconnection concerns. If none are identified, the customer receives a Certificate of Public Good and the system can be installed.[51]

- Future screens – Through the DPU, seek data on the nature of the interactive effects of greatest concern to utility planners/ systems, including a) any examples of these that have arisen to date; b) best practices in response; c) where information gaps exist in enabling safe and prudent interconnection under these circumstances.

Costs

- Match application fees with review complexity – While this occurs already in the form of the different fees charged for each review path, fee differentials could also reflect a) generator type; b) feeder status (i.e., as the number of DG on a single feeder increases, so too does the complexity of the impact modeling); and c) process rewards, e.g., a complex project requiring detailed impact analysis could recoup a portion of the study fees if 100% of any additional customer information is provided without slowing the study schedule.
- Make study fees contingent on deadline success – This could be accomplished by a) requiring the utility to remit a portion of the fees when studies aren't completed on time; b) providing a contingent reward (e.g., 5-10% of the study fee, withheld by applicant until study completion). With better data on the duration of study steps, it would also be possible to 'benchmark' a schedule for different types of impact and detailed studies, and reward the utilities for reviews that significantly beat the benchmark.
- Upgrade costs – Applicant acceptance of these costs may improve if they a) know in the application process what the technical requirements and resulting costs are likely to be, per their site location; and b) can view the posted decision criteria for whether or not specific upgrades are required. Utilities have the "110%" rule, which requires their cost estimates to be within that limit or the utility covers the difference. Applicants should be held similarly harmless against increases in upgrade costs after they have already accepted a lower estimate.
- Cost sharing – Section 4.3.3 of this report introduces several circumstances under which upgrade costs might be shared, whether between the utility and applicant (if the DG-related upgrade a) is either already in the utility's system improvement plans or b)

[51] See "Vermont enacts new law that streamlines solar PV registration to help ease permitting costs" in PV Tech at http://www.pv-tech.org/news/vermont_enacts_new_law_that_streamlines_solar_pv_registration_process_to_he

improves overall distribution system reliability; or between multiple DG owners on the same feeder. The Commission should encourage the utilities to look for and maximize the system-wide benefits of these win-win situations.

5. Federal-State Jurisdiction

A DG generator seeking to interconnect to the grid in Massachusetts must work with either – and sometimes both – of the two entities charged with ensuring the safety, reliability and efficiency of the electric supply: with either their local distribution company, under the MA Model Interconnection Tariff, or with the ISO New England (ISO-NE) using Schedule 23 for projects under 20 MW.

ISO-NE is the regional transmission organization (RTO) serving the six New England states. It is a private, non-profit corporation based in Springfield, MA, with 400 employees and responsibility for managing the bulk power supply for one of the most complex electricity markets in the US. ISO-NE is also charged with the "fair administration" of the region's wholesale electricity market. As an RTO, ISO-NE falls under the regulatory authority of the Federal Energy Regulatory Commission (FERC).

KEMA's survey found a significant level of confusion among DG applicants regarding the different State versus Federal interconnection processes, as respondents report difficulty determining which to follow. While the majority of respondents (52%) feel neutral about this issue, the survey results showed a substantial level of dissatisfaction on this point (37%). Respondents indicating dissatisfaction with their current understanding of the two interconnection processes and the distinctions between them is more than three times larger than the fraction that is satisfied (11%).

Many survey comments suggest that some parties to the interconnection process have not understood the delineation of roles and responsibilities between the State-regulated distribution companies and the FERC-regulated ISO-NE. In some cases, this ambiguity has resulted in misunderstandings and led – directly or indirectly – to a lengthening of time in the interconnection process. Some of the questions raised by respondents the survey include:

- What kinds of transactions are considered "wholesale sales." For example, one survey respondent reported being required to switch from State to Federal jurisdiction when they submitted an application for capacity payments;
- What participation in other ISO-NE and FERC-regulated markets trigger FERC jurisdiction over the interconnection process, for example participation in the Forward Capacity Markets; and
- DG operated as Independent Power Producers (IPP) may split the sale of their output to multiple customers, potentially including the distribution company. What

percentage of sales sold to the utility allows the generator to interconnect under State jurisdiction?

- What jurisdictional issues arise when the DG applicant seeks interconnection to – and market participation through – a spot or area network? How will the criteria of "previous wholesale activity" be applied to the multiple feeders of the secondary network(s) in question?

Of the small number responding to ISO-related questions on the survey, a substantial majority felt that it was "somewhat" or "very" important to clarify Federal versus State jurisdiction for interconnection process.

This section does two things: First, we review relevant provisions of the MA Tariff and the ISO-NE interconnection tariffs, and identify points of intersection and/or ambiguity between the two. Second, we identify potential approaches to improve the interconnection experience for projects that fall into these areas of ambiguity.

5.1 Comparison of MA and ISO-NE Interconnection Tariffs

Access to the ISO-NE transmission system and/or participation in New England's wholesale electricity markets are governed by ISO-NE's Open Access Transmission Tariff (OATT).[52] OATT sets forth the rules that electricity suppliers must follow, including responsibilities, forms and fees, to participate in the wholesale power markets. This Tariff also contains the rules governing the interconnection processes for both large and small generators[53] that wish to participate in these markets.

The application and approval process for all DG seeking interconnection will fall under the jurisdiction of either the State tariff approved by the DPU (the MA Model Interconnection Tariff) or the FERC-approved ISO-NE Tariff for either large or small interconnected generators. Even if the primary jurisdiction over the application is at the State level, there may also be reporting requirements to ISO-NE and involvement of the Transmission Owner, consistent with OATT and these interconnection rules. In general, the vast majority of DG interconnections have fallen under the jurisdiction of the MA DPU and in most of these cases, there has been little ambiguity

[52] The ISO-NE Open Access Transmission Tariff and associated rules, forms and documents are available at http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

[53] If a DG project is a Qualified Facility (QF), it may be treated differently. The Massachusetts process for interconnection of QF projects is not separately addressed in this section.

about jurisdiction. There are also situations where it is clear that a DG generator will be subject to the ISO-NE Tariff, for example due to clear plans to sell the power into the wholesale market.

5.1.1 MA Tariff References to ISO-NE

In Massachusetts, the DPU regulates DG interconnections that are under State jurisdiction. Such projects must secure interconnection approval from their local utility or distribution company, following the specific interconnection tariff of that utility. Each of these tariffs follows the MA Model Interconnection Tariff which was adopted by the DPU in April 2004, and amended in 2005, 2007 and 2009. Further detail on the MA Tariff has been provided in Section 3 and excerpts from the MA Tariff are included for reference as Appendix A.

The MA Tariff defines State-level jurisdiction over interconnection to apply to all interconnections which are not subject to the jurisdiction of ISO-NE:

> 5.1.1 Applicability: "1.1 .... This document ("Interconnection Tariff") describes the process and requirements for an Interconnecting Customer to connect a power-generating facility to the Company's Electric Power System ("Company EPS") …, <u>except as provided under the applicable ISO-NE tariff</u> and/or under the Qualifying Facility regulations in 220 CMR 8.04.[54]

As a result, it is not under the control of the Massachusetts utilities to determine which interconnection tariff should apply to any particular DG applicant. The fundamental jurisdictional issue will be addressed further in the following section on the ISO-NE Tariff.

There are several other provisions of the Massachusetts Tariff which make reference to ISO-NE criteria or decisions to exercise some degree of jurisdiction, review or approval over a DG interconnection or over its technical characteristics. Most of these provisions are excerpted in Table 5-1 below.[55] Some of these provisions depend upon whether a project is subject to ISO-NE requirements, but do not themselves include the criteria for such jurisdiction. Some of the following provisions of the MA Tariff address the criteria for triggering a responsibility to comply with reporting or other requirements of ISO-NE.

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[54] MA Model Interconnection Tariff, section 5.1.1, emphasis added.

[55] Emphasis added in Tables 5-1 and 5-2.

Table 5-1 Jurisdictional Issues in the MA Model Interconnection Tariff

MA Section #	Topic	Excerpts from MA Model Interconnection Tariff
3.3.3.b	Impact Study	The timelines in Table 1 will be affected if ISO-NE determines that a system impact study is required. This will occur if the Interconnecting Customer's Facility is greater than 5 MW and may occur if the Interconnecting Customer's Facility is greater than 1 MW.
Exhibit E	ISO-NE I.3.9 Approval	Detailed Study Agreement: The Interconnecting Customer understands and acknowledges that any use of study results by the Interconnecting Customer or its agents, whether in preliminary or final form, prior to ISO-NE I.3.9 approval,[56] should such approval be required, is completely at the Interconnecting Customer's risk.
8.0	ISO-NE Metering Requirements	Metering, Monitoring, and Communication. This Section sets forth the rules, procedures and requirements for metering, monitoring and communication between the Facility and the Company EPS where the Facility exports power or is net metered (sic) or is otherwise subject to ISO-NE requirements.
8.1	Communica-tion Requirements	Facilities which are 5 MW or greater are required by ISO-NE Operating Procedure No. 18 to provide communication equipment and to supply accurate and reliable information to system operators regarding metered values for MW, MVAR, volt, amp, frequency, breaker status and all other information deemed necessary by ISO-NE and the Local Control Center (REMVEC). [See other metering and communications requirements of ISO-NE.]
8.1	Losses	Losses between the Metering Point and Point of Receipt will be reflected pursuant to applicable Company or ISO-NE criteria, rules or standards.

In addition, there are several other provisions of the MA Tariff, included in Table 5-2 below, which make reference to ISO-NE requirements or criteria for applicability, including some references to project size as criteria.

[56] Determination, conducted by ISO-NE in accordance with Section I.3.9 of the ISO-NE OATT, that the Applicant's Proposed Plan will not have a significant adverse impact on the New England Transmission System.

Table 5-2 Technical Requirements in the MA Model Interconnection Tariff

MA Section #	Topic	Excerpts from MA Model Interconnection Tariff
4.1.5	ISO-NE Voltage Requirements	Facilities greater than or equal to 1 MW interconnected with the Company EPS shall be required to provide reactive capability to regulate and maintain EPS voltage at the PCC as per ISO-NE requirements. The Company and ISO-NE shall establish a scheduled range of voltages to be maintained by the Facility.
4.2.3	ISO-NE's Operating Procedures	4.1.1 Voltage regulation The DR [distributed resource] shall not actively regulate the voltage at the PCC [unless required by ISO-NE's operating procedures].
4.2.3.2.1.b	NPCC Criteria	The ISO-NE is responsible for assuring compliance with NPCC criteria. For the interconnection of some larger units, the NPCC criteria may additionally require….[balance of text]
8.1	Equipment Testing	All metering equipment installed pursuant to this Interconnection Tariff and associated with the Facility shall be routinely tested by the Company at Interconnecting Customer's expense, in accordance with applicable Company and/or ISO-NE criteria, rules and standards.

5.1.2 ISO-NE Requirements

In 2005, FERC issued Order 2006 Small Generator Interconnection Procedures (SGIP) which established the interconnection procedures for generators less than 20 MW, and an accompanying Small Generator Interconnection Agreement (SGIA). The order requested all public utilities that own, control or operate facilities under FERC's jurisdiction to file standard interconnection SGIP and SGIA to interconnect DG. FERC Order 2006 adopted many of the best practices interconnection rules recommended by the National Association of Regulatory Commissioners[57] in an effort to minimize Federal-State division and promote consistent, nationwide interconnection rules.

[57] National Association of Regulatory Utility Commissioners (NARUC) finalized its Model Interconnection Procedures and Agreement for Small Generation Resource in 2003. The NARUC model is based on the best practices of state regulatory agencies that have interconnection procedures for small generators.

Today, as described above, ISO-NE interconnection rules for both large and small generators are governed by specific schedules in the OATT. These materials may be accessed at: http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/index.html, including:

- **Large Generator Interconnection Procedures (LGIP)** – Large generators are those over 20 MW in size. The requirements for submitting a Generation Interconnection Request, including the requisite forms, are provided in OATT Schedule 22 – Standardized Large Generator Interconnection Procedures.
- **Small Generator Interconnection Procedures (SGIP)** – "Small generators" are those sized 20 MW and less. The requirements for submitting a Generation Interconnection Request, including the requisite forms, are provided in OATT Schedule 23 – Standardized Small Generator Interconnection Procedures.

This section summarizes key relevant provisions of the FERC-approved tariffs that determine jurisdiction over DG interconnection procedures and requests. By definition, the criteria for ISO-NE jurisdiction cover all circumstances that do not fall into three categories of exceptions. The ISO-NE Tariff states in Section 1.1, Applicability, that the Small Generator Interconnection Procedures ("SGIP") and Small Generator Interconnection Agreement ("SGIA") shall <u>not</u> apply to:

- o "(i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site;
- o "(ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or
- o "(iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility."

This same language is used in the definition of Interconnection Requests. To help clarify questions commonly asked by DG applicants, ISO-NE has provided a short guide for potential DG applicants entitled "Does the Interconnection Request go to ISO-NE?" Both this document and a September 2008 matrix entitled "Generation Interconnection Responsibilities: ISO-NE

Proposal" detailing ISO-State jurisdictional boundaries and responsibilities have been included in Appendix D.[58]

The language in the FERC/ISO-NE definition of jurisdiction makes it clear that the most important jurisdictional criteria is usually the nature of transactions for the sale of the DG's electric output. Even if a DG seeks to interconnect to a distribution line that is already FERC-jurisdictional, the interconnection may not fall under ISO-NE jurisdiction if it does not plan to sell its power into the wholesale market. On the other hand, even if a wholesale power sale is planned, an interconnection application would not be subject to the ISO-NE tariff if the distribution line is not FERC-jurisdictional "at the time the interconnection is requested."[59]

The MA DG Collaborative discussed some of these jurisdictional questions in 2006. The following excerpt from the Collaborative's 2006 Report is consistent with the above definition:

> "The Massachusetts Model Tariff … applies under the following circumstances: the Interconnecting Customer is a net-metered[60] customer, or the Interconnecting Customer is not exporting any kWh to the utility distribution system, or the Interconnecting Customer is exporting to a third party but is connecting to a non-FERC jurisdictional distribution feeder. This would be the case, for example, when DG project is the first wholesale customer on the distribution feeder, but the next DG project to export to a third party on that feeder would instead be subject to the ISO-NE rules.
>
> As a practical matter, even when the interconnecting customer may be exporting small quantities of power to the utility system, the Massachusetts Model Tariff will apply unless the export is metered and sold to a non-utility buyer AND the interconnection is made to an existing FERC jurisdictional distribution feeder. … With respect to the new ISO-NE process, eligibility works as follows: when a generator is interconnecting to a local utility distribution system, FERC jurisdiction is triggered when there will be a wholesale transaction and the distribution feeder to which the connection will be made is FERC

[58] "Does the Interconnection Request go to ISO-NE?" dated 4/21/2011, 3 pages, and "Generation Interconnection Responsibilities: ISO New England Proposal" provided to DOER by David Forrest, ISO-NE, as email attachments.

[59] Ibid., excerpt from Order FERC 2003, section 804: "This Final Rule applies to interconnections to the facilities of a public utility's Transmission System that, at the time the interconnection is requested, may be used either to transmit electric energy in interstate commerce or to sell electric energy at wholesale in interstate commerce pursuant to a Commission-filed OATT…."

[60] Net metering rules have changed substantially since 2006, raising potential questions about jurisdiction which are not addressed in this document.

> jurisdictional by virtue of a previous wholesale transaction. A wholesale transaction is one in which the sale of excess power is to a third party, not the Distribution Company….
>
> When FERC jurisdiction applies, the DG proponent will be directed to submit an application to ISO-NE – not to the applicable Massachusetts Distribution Company – and will be subject to the ISO-NE's rules for interconnection of small generators, not to the Model Tariff addressed by this Report."[61]

It is important to clarify one point. The ISO-NE Small Generator Interconnection Tariff (Schedule 23), does not determine jurisdiction based solely on generator size (i.e. > or < 2 MW).

Nevertheless, for projects that are greater than or equal to 5 MW, there are some changes in the treatment of the DG project based on their size, even though the interconnection process is subject to the jurisdiction of the Massachusetts tariff, including:

- ISO-NE becomes a participant in the impact study (but ISO-NE does not assume the lead role in that study based on size), and
- The DG project is subject to the ISO queue.

All DG projects, FERC- and State jurisdictional, are required to satisfy the requirements of ISO-NE's planning process for new generators (Planning Procedure or PP 5-1), which can be found on the ISO-NE website.[62] PP 5-1 provides that for the smallest generators, less than 1 MW, no forms are required. For generators from 1 MW to 4.999 MW, a notification form is required to go to the NEPOOL Reliability Committee. For generators greater than or equal to 5 MW, studies and contracts are required to go to the Stability and Transmission Task Forces as well as the Reliability Committee. At or above 5 MW, a stability model will likely be required, and a transmission study may be required. If no transmission study will be required, the Task Forces need to agree; this is often the case for generators between 5 and 10 MW.

A slightly different process may apply to any projects which do not intend to sell power into the wholesale market but which seek to interconnect to the PTF or Non-PTF Transmission system. There may not be many such projects, but the Transmission Owner is to take responsibility for handling the application and lead the impact study since the interconnection is at the transmission level.

[61] DG Collaborative 2006 Annual Report, Section 3.3, page 27.

[62] This paragraph is based on information emailed by David Forrest, ISO-NE, June 2011.

The distribution company also participates in the impact study.[63] According to the September 2008 matrix entitled "Generation Interconnection Responsibilities: ISO-NE Proposal" (Appendix D) the Interconnection Agreement may be signed by the Transmission Utility even though the interconnection itself may be subject to the State interconnection process.[64]

5.2 Discussion of Potential Approaches

The increasing volume of larger DG projects suggests that the export of generation could also be on the rise. Growth in the volume of exporting generators is also likely to trigger an increase in the number of FERC-jurisdictional lines, leading to the likelihood of additional FERC-jurisdictional projects in the future.

Many of the issues addressed in this section lend themselves to collaborative action across the six states in the ISO-NE region. We have worded the following recommendations in terms of "the State agencies" to allow flexibility of interpretation. At minimum, DOER should consider taking the lead; where possible, that leadership may result in a "coalition of the willing" among the New England states similarly affected by ISO-NE jurisdictional ambiguities.

Develop guidelines to explain State-Federal jurisdictional boundaries. In its 2006 Annual Report, the MA DG Collaborative recommended the development of educational materials targeted toward developers, to assist them in determining the appropriate application process for their projects. Specifically, the 2006 Report recommended a series of steps:

> "The DTE, ISO-NE and interested parties should work together to clarify the process that will apply to a customer under state or FERC interconnection jurisdiction, including (*numbering added):*
>
> (a) …(identifying) what will happen if a customer changes plans or actions (e.g., what happens if a customer who has been selling excess generation only to the Distribution Company subsequently decides to sell excess generation to a wholesale trader).
>
> (b) … A set of clear guidelines should be developed to handle any transfer of responsibility (and files) that might occur between the ISO and the Distribution Company.

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[63] Often the distribution company and transmission owner are different subsidiaries of the same company.

[64] The treatment of DG projects which do not intend to sell power into the wholesale market but which seek to interconnect to the PTF or Non-PTF Transmission system is one area in which clarification by all parties involved would be helpful.

(c) Periodic meetings may be needed to maximize the consistency and uniformity of procedures to address the above issues, and other issues as they arise.

(d)… further activity be initiated to maximize uniformity between the … processes discussed herein, and to continue to streamline the overall Massachusetts Interconnection process on a state and region-wide basis."

The survey results suggest that it would still be helpful for the utilities and ISO-NE to develop that "set of clear guidelines." In addition, DOER could initiate a dialog among the regional state energy policy agencies regarding the usefulness of collective work on the issues discussed in this section. On behalf of this group or on behalf of the MA DG industry, DOER should approach ISO-NE to clarify and harmonize definitions and boundaries between the State and Federal jurisdictions and procedures. In particular, we recommend that DOER take the initiative to clarify:

- Definitions of 'wholesale sale' – what volume or duration of export (sale beyond the distribution company) triggers FERC jurisdiction;[65] and
- The impact on State vs. Federal jurisdiction for DG which receives capacity payments and/or participates in any FERC-regulated markets, without entering into long-term wholesale sales contracts.

Enhance applicant education on ISO-NE review processes. The multi-state work group should identify appropriate content for the Interconnection Workshop proposed for all DG applicants with projects likely to be FERC-jurisdictional. Attendance at such a session could be mandatory for all applicants a) proposing DG projects of any size; b) on a FERC-jurisdictional line; and/or c) contemplating sale into wholesale markets. These sessions should:

- Inform applicants that key distinction for jurisdiction is how the output is being sold and whether that sale is considered a wholesale transaction or not;
- Encourage DG developers to seek interconnection at the appropriate interconnection level for their project size – transmission or distribution – to avoid additional costs;
- Increase general awareness among developers of both small and large DG projects of the interconnection process, including the ISO-NE queue and the costs and timeframe it entails; and

[65] This question is raised and discussed in the MA DG Collaborative's 2006 report, page 28.

- To the extent possible, utilize in this effort materials already developed and/or approved by ISO-NE.

Develop procedures to change between State and Federal processes. According to the ISO-NE Tariff, the question of FERC-State jurisdiction is determined by the circumstances when a DG project applies.[66] However, changes in project characteristics can trigger additional review processes required by the ISO review process, which can impose additional cost and time requirements on a proposed DG project. Project developers may take action to mitigate these costs through changes in project design and/or business model. This is an example where a distributed generator could be subject to one process but later be required to go though some of the steps of the other process. Potential changes in review process steps might be triggered by a number of circumstances:

- o A project exporting to the location distribution company chooses to contract for a portion or for 100% of its power to a non-utility purchaser;
- o The DG project changes its business model in order to participate in wholesale market transactions, like capacity payments.
- o State or Federal policy supports change in the future, triggering other changes in DG project economics, business model and/or market participation.

Our review did not find any evidence of a uniform, efficient procedure to handle the move between jurisdictions. The state energy policy agencies should work with ISO-NE to develop guidelines that govern changes in jurisdiction while project review is underway. These procedures should cover: the transfer of studies completed in one jurisdiction to the other (at minimum); the completion of studies by the receiving jurisdiction with minimum amount of separate fees and/or delay. In an ideal world, this effort would result in a single set of study parameters and assumptions, such that studies could be initiated under either jurisdiction and serve the purposes of the other without incurring any additional cost or delay.

[66] Information emailed by David Forrest, ISO-NE, June 2011.

6. Secondary Distribution Networks

Distribution networks are special configurations of the secondary distribution system commonly found in urban areas where there are a large number of loads in a relatively small geographic area. The Massachusetts Tariff [67] defines networks as follows:

> "'Network Distribution System (Area or Spot)' shall mean electrical service from an EPS[68] consisting of one or more primary circuits from one or more substations or transmission supply points arranged such that they collectively feed secondary circuits serving one (a spot network) or more (an area network) Interconnecting Customers."[69]

Networks pose unique technical challenges to the interconnection of DG. Because of those challenges, many types of DG installations are generally not approved for some of the most populous areas of the Commonwealth.

This section addresses the challenges associated with DG interconnection in secondary distribution networks (both spot and area networks), summarizes work that has been done to address them in both Massachusetts and nationally, and suggests possible steps ahead. Specific recommendations are introduced below and summarized in Section 8.

6.1 Background on Networks in MA

Chapter 2 of the DG Collaborative's 2005 Report lays out in the detail the 16 specific technical challenges raised by the interconnection of DG into such networks.[70][71] The MA Tariff provides "a Simplified interconnection path for Listed single-phase inverter-based DG Facilities with power ratings of 15 kW or less requesting an interconnection on spot networks when the

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[67] The same definitions are used in the MA Model Tariff for the four utilities in Massachusetts.

[68] "Company EPS" shall mean the electric power system owned, controlled or operated by the Company used to provide distribution service to its Customers.

[69] http://nuwnotes1.nu.com/apps/wmeco/webcontent.nsf/AR/Interconnection_Tariff/$File/Interconnection_Tariff.pdf

[70] DG Collaborative's 2005 Annual Report, May 31, 2005, Chapter 2, pages 82-104. See Table 2.5, page 93-94 for the list of 16 specific technical challenges facing DG in area networks.

[71] For additional description of area and spot network distribution systems, see Section 5 of the DG Collaborative's 2003 Report, "Overview of Network Interconnection Opportunities and Challenges for DG"; Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts Submitted to the Massachusetts Department of Telecommunications and Energy in Compliance with DTE Order 02-38-A by the Distributed Generation Interconnection Collaborative, March 3, 2003.

aggregate DG Facility capacity is less than one-fifteenth of the Customer's minimum load."[72] The Tariff requires that other interconnection applications on spot networks and all applications on area networks use the Standard Process.

A few interconnections have been approved on spot networks, most or all of which are inverter-based. A recent example is a photovoltaic-thermal hybrid solar system with 30 kW of PV capacity on the Thomas P. O'Neill, Jr. Federal Building in Boston, which went through the Standard interconnection process.

Figure 6-1 Rooftop 30 KW PV System on O'Neill Building, Boston

Interconnection to an area network is much more difficult than for a spot network, as explained in the DG Collaborative's 2006 Report section 3.2.2, Differences Between Spot and Area Network Issues.[73] Two factors in particular can reduce or mitigate the operating risk that DG poses to an area network, as documented in the extensive discussion in the DG Collaborative's 2005 Annual Report[74]:

- **Generator Type** – The operating risk posed by DG in a network setting is significantly affected by the type of DG installed. All else being equal (generator size, location in the network placement and network loads, etc.), inverter-based systems are more suitable than two other common types of generators: induction motors and synchronous generators. Inverter-based systems generally produce relatively small amounts of fault current compared to other DG types, which can be a critical limitation on networks. In

[72] MA Model Interconnection Tariff, Section 3.1.

[73] However, see section 3.0 above for treatment of area networks in two other states.

[74] Op Cit. DG Collaborative 2005 Annual Report, Chapter 2, pages 98, 99.

addition, based on current industry standards, inverters are also designed to automatically shut down within a few cycles of detecting loss of the secondary network. This helps to prevent the occurrence of unplanned electrical islands, another significant operating concern.

- **Generator Size versus Network Load** – As long as the net output of all DG in the network remains low relative to the total network load, the probability of any reverse flow from the DG remains low.[75] This minimizes the risk that network protectors will open due to reverse power flow (whether real, reactive or both, depending on the design and settings). Network protectors are used to prevent infrastructure overloading and damage, such as flow through conditions, regardless of DG impacts.

In recognition of the challenges inherent in network interconnection of DG, the DG Collaborative has addressed this issue many times over the years, recording the challenges and posing potential solutions in reports from 2003 through 2006. As one example, the Collaborative's 2005 Annual Report, submitted May 31, 2005, devoted substantial discussion to these issues. This included specifically Chapter 2, recommendations in the 2005/06 work plan and a companion report on the DG installations on the spot network at the GSA Williams Building in Boston[76].

The three subsections that follow summarize actions taken by the Collaborative to a) communicate with DG applicants seeking area network interconnection; b) pursue and encourage solutions through technology development, and c) encourage progress on network interconnection in other forms.

6.1.1 Communications Protocol for Area Network Inquiries

In the absence of technical guidance on the best way to approach the technical, safety and reliability concerns implied by DG interconnections in networks, the DG Collaborative agreed in 2005 on a method for the utilities to handle DG applications in these areas. Applicants that submit an application to interconnect in any MA area served by an area network will receive a

[75] Even without DG, networks face potential issues of back-feeding from network transformers. It is usually determined, however, that the source of back-feeding current (such as an elevator) is relatively small with respect to total load.

[76] Feero, William E., P.E., Generation Monitoring at the GSA Williams Building and Modeling of Feeder Fault Cases Recorded, submitted to Massachusetts DG Collaborative May 18, 2005.

letter from the utility. We have extracted from that letter the following description of the options available to the applicant:

> Dear [DG Applicant]
>
> …. If you have already submitted a completed Interconnection Application the next step will be an initial review when [Company] will work with you to identify solutions that allow for your Facility's operation. Alternatives will not include the parallel interconnection of your Facility to an area network. However, with significant design modifications it may be possible to operate your Facility. These alternatives could include:
>
> - Transferring your load from an area network to a radial distribution system, which would allow the parallel interconnection of the Facility;[77]
> - Connecting the generator to a radial distribution system, which would allow parallel interconnection of the Facility; and
> - Allowing your location to operate off the grid by utilizing the Facility to self-generate for specific load requirements. You have the option to install an open transition switch to the utility system.[78]

In our interviews with the utility respondents, they reported that they receive inquiries about potential projects in networked territories, in some cases as often as once a month. They respond to customers in several ways, by:

- Correcting the applicants' understanding of the location: "I got maybe 20 calls to ask if (the proposed project) was on network locations in towns that don't have networks at all...."
- Offering a non-network solution: [Utility A]"….we offer options to request radial (lines) or install without interconnection....;" [Utility B] "….in our case it would be easy to connect them off-network…. we have other underground supplies in the same area...."
- Telling them that "interconnection is not allowed in an area network."

Regrettably, the above "non-network solutions" usually result in a no-go for a project developer, due to the additional cost required. If the proposed location has access to an alternate radial

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[77] At the applicants' cost.

[78] Ibid, Appendix 2.2, page 116.

feeder, the project may proceed with interconnection to that line. If not, however, the developer's options are limited to a) pay to build a new feeder from the project to the transformer serving the area, and any upgrades that are needed to transformer capacity; b) pay to build a new line to the next closest non-network feeder; or c) "operate off the grid," i.e., as a stand-alone system with no ability to net meter or sell. Given these options, it should not be surprising that DG developers no longer submit applications for projects in areas known to be served by an area network.

6.1.2 Technology Development Opportunities

This section describes recent or new technologies that may have the potential to reduce the challenges of DG interconnection to distribution networks.

First, the MA DG Collaborative 2006 Annual Report addressed potential development of technology for relaying and control for spot networks in its Appendix F. [79] As stated in the report:

> an "RFP has been created to advance the acceptability of DG on networks by developing advanced network protector relays and establishing high-speed communication between network protectors and DG units. This combination should enable DG units to react essentially instantaneously to any adverse situations (e.g., faults, reverse power flow, etc.). whereas today the DG units do not react appropriately until voltage, current or frequency range outside of normal values."

The technology development work recommended by the DG Collaborative was pursued for a time by the Massachusetts Technology Collaborative. A general agreement was reached with the California Energy Commission to coordinate the two states' respective technical work, and contact between the two agencies was maintained for several months. After that period, however, California's research priorities shifted to different areas and did not include the anticipated joint work on development of new technology. Other potential coordination and joint funding among multiple states and Federal agencies was explored but sufficient funding and partners were not found to proceed with the RFP. At that time, there was no collaborative or regulatory process in the state to pursue this potential technology development further.

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[79] See March 3, 2003 Massachusetts Distributed Generation Interconnection Collaborative, Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts, Section 5; see also D.T.E. 02-38-B, May 31, 2005, 2005 Annual Report, Massachusetts Distributed Generation Collaborative, Section 2; see also Feero, William E., P.E., Generation Monitoring at the GSA Williams Building and Modeling of Feeder Fault Cases Recorded, submitted to Massachusetts DG Collaborative May 18, 2005; see also D.T.E. 02-38-C, June 30, 2006, 2006 Final Report, Section 3.2 and Attachment F: Relaying and Control Technology Development for Spot Networks.

6.1.3 Boston PV Monitoring Demonstration

The City of Boston provides a case example of the challenges and potential of interconnecting DG in area networks. In 2008, Mayor Thomas M. Menino committed the City to growing the installed PV capacity from 0.5 to 25 MW by 2015 through the Solar Boston program. The Boston Solar Map provides current and potential PV customers in the City with a visual aid to the growing penetration of PV in Boston.[80] However it has been necessary for a disclaimer to accompany the Map, acknowledging that PV "generally cannot be connected" in the area network in downtown Boston due to concerns about grid reliability.

However, NSTAR has initiated a Smart Grid Demonstration project to test a new approach for interconnection of solar PV in a portion of the Boston area network with funding from the American Recovery and Reinvestment Act (ARRA) of 2009. NSTAR has selected one of its 12 secondary area networks in downtown Boston to serve as a testing ground for adding increased monitoring capabilities at various locations around the network.[81] The following description is taken from a 2010 report on this "Urban Grid Monitoring and Renewables Integration" effort:

> "NSTAR has selected this grid based on the suitable mix of commercial and residential customers, as well as the location of recent demand for PV-type solar installations."[82] As such, NSTAR is installing additional monitoring capabilities at several areas and with different functionality. On the area network itself, NSTAR has designated 500 manhole locations monitoring "nodes." These nodes are classified as major or minor. At the minor nodes, relatively simple and lower cost monitoring devices will be used to detect high or low currents or voltages as well as cable temperatures. The information these devices collect will be transmitted via radio waves to patrol vehicles that capture the data and use it to identify potential problems on the underground network sections.
>
> At major nodes, more sophisticated monitoring equipment will be installed. This technology will provide continuous current sensing and have communications capabilities that facilitate near real-time monitoring of the major nodes for system operators. Monitoring and control equipment will also be upgraded at two distribution

[80] Boston Solar Map http://gis.cityofboston.gov/solarboston/.

[81] "Smart Grid Projects at NSTAR", a presentation to the New England Restructuring Roundtable, December 4, 2009 by Larry Gelbein, NSTAR. Slides downloaded from www.raabassociates.org/Articles/Gelbein_12.4.2009.ppt.

[82] Urban Grid Monitoring and Distributed Resource Integration. Erik Gilbert, Larry Gelbien, Robin Maslowski. 2010

substations to include programmable logic controllers (PLC). These PLCs will allow for continuous data collection and additional control capabilities.

Additionally, “smart” meters will be installed at all solar-PV installations. The meters will monitor power consumption and solar-PV production at the customer site and provide this critical information to system operating centers or as inputs to a more complex and automated distribution system.

These enhancements allow for more comprehensive monitoring of the power system which enables system operators to make more informed decisions in real-time. As more monitoring capabilities are put in place, greater numbers and more widespread interconnections will be achievable while still maintaining grid reliability and safety. The data collected by this new technology will also impact utilities’ strategic and economic planning efforts.

“This additional instrumentation will provide enhanced information that will be made available to other analysis applications over the internal, secure network. The data will be used to improve on-line engineering analysis, and it will provide unprecedented visibility and operational status awareness, as well as a much more accurate asset inventory.”[83]

6.2 Network Interconnection Experience

Thus far, experience in Massachusetts has led to the impression that DG interconnection into spot networks is challenging and into area networks, impossible. Yet experience is accumulating nationally to suggest that, under specific circumstances and with additional protective requirements, interconnection of inverter-based DG into both types of secondary networks can be feasible. In fact, such DG integration occurs routinely in many low voltage networks in Europe.[84]

[83] Gilbert, Eric; Gelbein, Larry; Maslowski, Robin; “Urban Grid Monitoring and Distributed Resource Integration,” 2010, page 3.

[84] See “European Renewable Distributed Generation Infrastructure Study – Key Lessons Learned from Electricity Markets in Germany and Spain”, California Energy Commission consultant study draft report, by KEMA Inc., July 2011.

6.2.1 Secondary Network PV Case Studies

A 2009 NREL study[85] examined six cases of medium- and large PV systems installed into spot and area networks. All were fully monitored and performing successfully to date, having caused no export to the utility networks or other performance issues for the interconnecting utilities. From these examples, the NREL researchers identified both conditions and requirements that enable the interconnection of DG in these secondary networks:

- **Establish the facility's minimum load** – The prevailing concern regarding DG in networks lies in the potential for reverse power flow from the DG into the network, thereby triggering network protectors. By ensuring that the hosting site or facility always requires some amount of utility power, the likelihood of any DG export into the network is minimized.

  Accordingly, step one in this process is sizing the DG appropriately relatively to the load being served. In all of the success stories, the maximum PV output was considerably less than the minimum load of the facility, under weekend, evening and/or other periods of minimum use. In the majority of cases profiled, this size relationship was a requirement for interconnection.

- **Existing utility protection** – In most of the success stories, the DG facility was located in a network that incorporated network protectors on all network transformers which had already been converted to micro-processer based units from the older electro-mechanical network protectors, with monitoring of relays and protectors through Supervisory Control and Data Acquisition (SCADA) systems. These systems enabled the utility to continuously monitor the performance of the protection devices throughout the network in which the DG system was operating.

- **Safety measures to ensure no export** – Two kinds of relays can be deployed to ensure that no power from the DG system is exported into the network. Utilities may require applicants to install these protective devices:

  - Minimum Import Relays (MIR) – These relays are set to ensure that the facility always imports a specified level of utility power. Should the facility's demand drop below the minimum import amount, the potential is increased that the DG

[85] Coddington, M. et al "Photovoltaic Systems Interconnected onto Secondary Network Distribution Systems – Success Stories", Technical Report NREL/TP-550-45061, April 2009.

system's output will not be consumed on-site but instead exported into the network. Under these conditions, the relay will trip off the DG system.

- o Reverse Power Relay (RPR) – This relay is set close to zero, to ensure that the DG system is tripped off in any instance where it detects the presence of reverse power flow.

- o Dynamic Controlled Inverters (DCI) – Inverters so-equipped (see following section) eliminate the possibility of export into the network by controlling the output of the inverter. Controlling output at the inverter offers an advantage over the relays, as the latter may require reset by a technician once they have tripped off.

6.2.2 Dynamic Controlled Inverters (DCI) [86]

The DG industry itself is moving toward the incorporation of new features in inverters. [87] These components already adhere to UL 1741 as well as 1547-2003. Increasingly, industry-leading inverter manufacturers have incorporated such options into their utility-scale units:[88]

- Controllable low and high voltage ride-through;
- Dynamic VAR support;
- Power factor control;
- Controlled ramp rate;
- Remote control of real and reactive power;
- Communications capability, ready to integrate directly into utility SCADA systems; and
- Dynamic control features.

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[86] Ibid, slide 11.

[87] Inverter technology has now been added to some cogeneration systems based on rotating equipment, in addition to solar PV, to serve as part of the interconnection to network distribution systems.

[88] While we note that "utility friendly" is not the same as "network friendly", a full list of "Utility Friendly" features may be of interest. See Ray Hudson's presentation "High Penetration Photovoltaics Workshop", NREL, May 20, 2010, slide 3, available at http://www.nrel.gov/eis/pdfs/hppv_p3_t1_hudson.pdf. Products with such features include Solectria Renewables (www.solren.com), SatCon (www.satcon.com) and AMSC's D-VAR products (http://www.amsc.com/products/transmissiongrid/reactive-power-AC-transmission.html)

Dynamic Controlled Inverters (DCI) have incorporated communications and control features within the inverter that allow the DG to operate more like a traditional generator. The inverter controls incorporate thresholds that trigger inverter control of reactive power levels, under/over-voltage and frequency, and real power output. This includes the ability to set ramp rates and even to curtail system power output entirely when specific set points are reached. With the incorporation of DCI, DG seeking network interconnection can ensure that no export occurs. While the potential for curtailment must be taken into account in project financing, DCI still enables dynamic control of output – including partial curtailment and/or resumption of operations – as conditions allow. DCI can help ensure that DG systems can operate successfully in secondary distribution networks.

In addition to these current products and features, the next generation of UL 1741 is expected to be upgraded to IEEE 1547.8[89] Since both FERC 661A and several of the European standards require features like low-voltage ride through for some forms of DG (e.g., wind and/or PV), these features may become more readily available in the near-term.

6.3 Status of IEEE Guidance

In the absence of technical experience drawn from each utility's own experience, system planners rely on protocols developed by the Institute of Electrical and Electronics Engineers (IEEE) to provide guidance relative to DG interconnections in area networks. Concurrent with the discussion in Massachusetts, work has been underway nationally through IEEE, specifically the 1547 series, that provides IEEE-endorsed standards for interconnecting distributed generation to electric power systems.

IEEE 1547-2003 addresses the requirements for DG interconnection in terms of "the performance, operation, testing, safety, and maintenance of the interconnection requirements – voltage regulation, grounding practices,… paralleling device, (and) spot network connections…."[90] IEEE 1547-2003 provides the following criteria for interconnecting "DR" (distributed resources) to a spot network on the Electric Power System (EPS):

- Network protectors shall not be used to separate, switch, serve as breaker failure backup or in any manner isolate a network or network primary feeder to which DR is

[89] Ibid, slides 5-7.

[90] KEMA Inc., "Guidance Document for Customer Owned Distributed Generation Applications: A Working Draft", June 26, 2009; page 2-8.

connected from the remainder of the Area EPS, unless the protectors are rated and tested per applicable standards for such an application.[91]

- Any DR installation connected to a spot network shall not cause operation or prevent reclosing of any network protectors installed on the spot network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the Area EPS.
- Connection of the DR to the Area EPS is only permitted if the Area EPS network bus is already energized by more than 50% of the installed network protectors.
- The DR output shall not cause any cycling of network protectors.
- The network equipment loading and fault interrupting capacity shall not be exceeded with the addition of DR.[92]

IEEE 1547-2003 does not address the application of DG in networks, however, the MA DG Collaborative followed with interest[93] the development of IEEE P1547.6: *"Draft Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks."* IEEE P1547.6 is intended to amend to IEEE 1547-2003, specifically to codify recommended practices for interconnecting DG into both spot and area networks. As of June 2011, IEEE P1547.6 is still under final development – it has been voted on by IEEE standards members and approved with comments. A ballot resolution group with representatives from NREL and the utilities has been addressing the comments received during balloting. The expectation is that a revised final version of P1547.6 will be released in 2011.

6.4 Discussion of Potential Solutions

Massachusetts utilities and other stakeholders have addressed the technical concerns about network interconnection in recent years at the state level, and some potential solutions have been investigated. Going forward, new technical developments should continue to be monitored and experience from interconnection of PV and other inverter-based systems into networks in Massachusetts and other states should be used to inform and instruct potential network applicants. These steps should be incorporated into a) current utility communications

[91] IEEE C37.108TM-2002 [B8] and IEEE C57.12.44TM-2000 [B9] provide guidance on the capabilities of network systems to accept distributed resources.

[92] IEEE Standard 1547-2003, Section 4.1.4.2

[93] The DG Collaborative participated in this process from 2005 to 2008.

with applicants to spot and area networks; and b) the curriculum for utility-run DG applicant workshops.

Additional progress will likely follow final release of 1547.6. Massachusetts stakeholders should then revisit the technical and regulatory options open at that time through an appropriate collaborative process. This is consistent with the Department's direction to the Collaborative in its February 2004 Order, approving plans to:

> "..form a technical group under the umbrella of the ongoing Collaborative to study network interconnection experience and procedures; and provide regulators, customers, DG providers, utilities, and others with a clear explanation of the opportunities, challenges, and potential solutions posed by interconnecting to networks." (D.T.E. 02-38-B at page 7).

This technical group is described in MA DG Collaborative 2006 Annual Report, Chapter 3.2.1, General Discussion of Accomplishments and Technical Issues.[94] Re-establishment of such a group would provide a process through which potential approaches could be considered and presented to regulators. This should include a review of why DG interconnection has been so successful in European low voltage networks, and whether any European practices are applicable to future DG integration into spot and area networks in Massachusetts. The timing may be right for such a process in view of recent and potential progress on IEEE 1547.6, summarized above.

We end this discussion with three conceptual approaches, each of which can build experience with DG in secondary networks. Through this additional experience, and in combination with the guidance expected from IEEE 1547.6, we expect that further progress will be made on these challenging technical issues.

Increase opportunities for small inverter-based DG under specific conditions – The MA Tariff provides "a Simplified interconnection path for Listed single-phase inverter-based DG Facilities with power ratings of 15 kW or less requesting an interconnection on spot networks when the aggregate DG Facility capacity is less than one-fifteenth of the Customer's minimum

[94] See March 3, 2003 Massachusetts Distributed Generation Interconnection Collaborative, Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts, Section 5; see also D.T.E. 02-38-B, May 31, 2005, 2005 Annual Report, Massachusetts Distributed Generation Collaborative, Section 2; see also Feero, William E., P.E., Generation Monitoring at the GSA Williams Building and Modeling of Feeder Fault Cases Recorded, submitted to Massachusetts DG Collaborative May 18, 2005; see also D.T.E. 02-38-C, June 30, 2006, 2006 Final Report, Section 3.2 and Attachment F: Relaying and Control Technology Development for Spot Networks.

load."[95] These thresholds could be reviewed or technical guidelines could be developed to facilitate additional installations. Growing national experience also indicates that DG units small in relation to the facility load can be interconnected into area as well as spot networks under some circumstances. Particularly in networks where network protectors have been upgraded with communications and microprocessor-based units, utilities should be encouraged to develop guidelines that will allow some amount of DG.

Encourage utilization of "network -friendly" components – DCI-based systems represent a promising development in the interconnection of DG in secondary distribution networks. The harmonization of standards regarding the distribution system support functions required of larger DG is heading in the same direction – toward technology-based solutions for network interconnections. DG applicants seeking interconnection into any form of network should be made aware of and encouraged to incorporate components with these "network-friendly" features. Over time, such requirements may be incorporated as screens in the MA Model Tariff. This could allow creation of an Expedited path (in addition to the Simple Spot Network path which already exists) for some of the network applicants that would under current rules face a full Standard review process.

Develop voluntary "DG Carrots" – Identify ways to preferentially reward utilities for voluntary steps that break through the specific issues of networks. These could include preferential treatment of investments to upgrade monitoring in areas of high likely DG penetration. Or, more generally, "carrots" could be developed for the recognition of utilities that proactively plan to ensure that their distribution system is as ready as possible for DG, in terms of its network protectors, SCADA capabilities, etc. Such 'carrots' might include, for example, that utilities proactively encouraging DCI and other DG supports gain enhanced or preferential consideration for rate-basing the utility-paid portion of the associated capital costs of those upgrades.

[95] MA Model Interconnection Tariff, Section 3.1.

7. System Planning, Integration and Transparency

As shown earlier, Massachusetts has a significant level of DG at present and more ahead. This growth has created uncertainties for utilities that are responsible for the safety, reliability and power quality of the distribution grid. Since DG growth is expected to continue, it is important for the MA utilities to plan for a future with different characteristics than the era past. In this future, DG will continue to represent an increasing fraction of the power supply. Perhaps more critically, the decentralized and customer-dependent characteristics of DG will increasingly impose new demands on the utilities' ability to forecast, plan and operate the distribution grid.

At the same time, both DG applicants – customers, owners and developers – join utility planners and managers in seeking the same outcomes: a safe, effective and efficient process to integrate that DG into the distribution system. This section addresses three main topics, while also providing a glimpse into the next period of DG growth.

- *Transparency* – This term has been used throughout this report to refer to the ability of DG applicants to access, understand and plan for the application review process. The MA system also provides a process to resolve disputes when decisions are perceived as unfair.
- *Integration into Near-term Planning* – We summarize current approaches to the analysis of DG and its consideration in the context of utility system planning, e.g., the benefits of forecasting for the higher penetration rates ahead.
- *Planning for High-Volume DG* – A look at some of the steps taken by other jurisdictions to guide the penetration of DG to areas of maximum benefit to the distribution system.

7.1 Transparency

One of the main complaints about the interconnection process is the lack of transparency to DG applicants regarding the utilities' decision to reject an application, ask for certain information, or require certain equipment upgrades to be installed. In addition, utilities do not currently disclose whether there may be other applicants trying to access the same circuit. Since this information might influence a developer's decision to move forward, they find this lack of transparency an unnecessary barrier.

Industry respondents also report a lack of clarity regarding the degree of freedom utilities have to interpret the interconnection tariff. Applicants are unclear whether and/ or when utilities must seek guidance from DPU and when they can determine their own policies for applying interconnecting standards. Terms and conditions in the MA Interconnection Tariff may be clear to the utilities but are far less clear to applicants. In one particular instance described in a letter from DOER to NSTAR, the utility imposed a setback requirement for a wind turbine in a manner that was not anticipated in the MA Tariff or reviewed by the DPU.[96]

Throughout this report, we have used the term “transparency” to refer to the ability of applicants – or any other process observer – to understand the basis for decisions made at different points in the process. The “best practice” of full transparency requires that the process steps, timelines and costs be posted and accessible to all interconnection participants. The MA Tariff fulfills many of these transparency requirements, as the three pathways, decision screens, timelines and costs are all published, posted and spelled out in detail. Each of the MA utilities has also adopted the MA Model Interconnection Tariff, thereby providing a basis for consistency and comparability across the state. As discussed in Section 4, these steps have been the basis on which Massachusetts has been awarded an A in the national ranking “Freeing the Grid.”[97]

Yet the survey results showed that two elements of transparency come in for repeated questioning: information, particularly pertinent to decisions made in the review process, and consistency. As reported in Section 3, Standard and Expedited applicants in particular found the interconnection process to be burdensome, lengthy, inconsistent and lacking in transparency.

Information and decision transparency – The survey required that respondents have experience in the basic interconnection process; most had completed projects interconnected (see Figure 2-7). Nonetheless, despite their interconnection experience, respondents reported significant gaps in the information they need for efficient participation in the interconnection process.

The survey asked respondents how important they consider four categories of information that might be needed in the application process. Figure 7-1 below shows the importance applicants place on each of those categories. Using a scale from 1 to 10 where 10 is “very important,” 5 is “somewhat important,” and 0 is “not important at all,” respondents rated all four of the information categories above 8.5 in importance.

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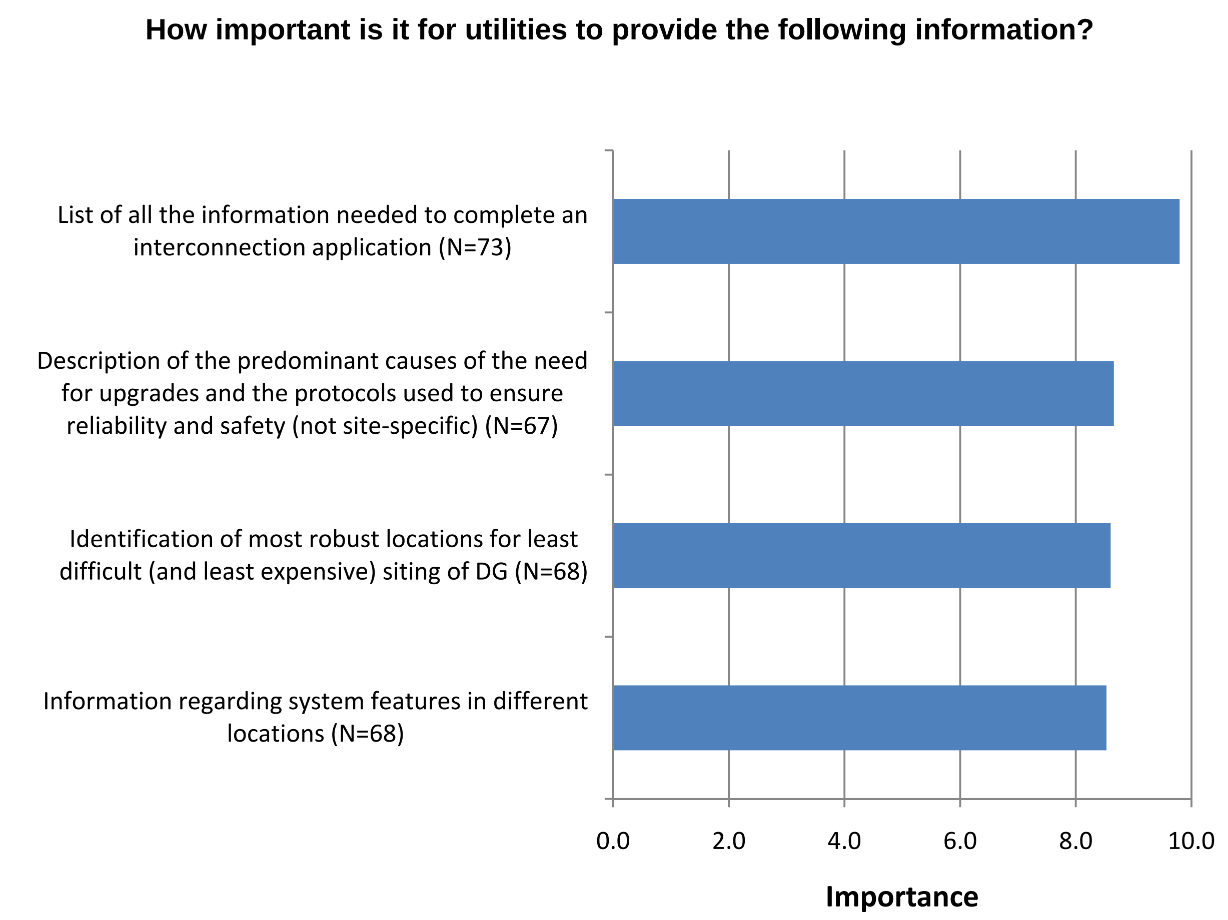
[96] Letter to NSTAR provided by DOER.

[97] “Freeing the Grid”, 2010 edition, pages 11-13.

Notably, 95% said that a “List of all information needed to complete an interconnection application” is Very Important. Comments from the survey – as well as data discussed in Section 3 regarding the reasons for incomplete applications and process delays – suggest that in the current process is not meeting this need.

Similarly, 89% rated as Very or Somewhat important that utilities provide a “Description of the predominant causes of the need for upgrades and the protocol used to ensure reliability and safety.” As discussed further below, this need for this information was reinforced by numerous comments about inconsistencies within and across utilities regarding the reasons why studies, project modifications, system upgrades, etc., were required in their specific situations.

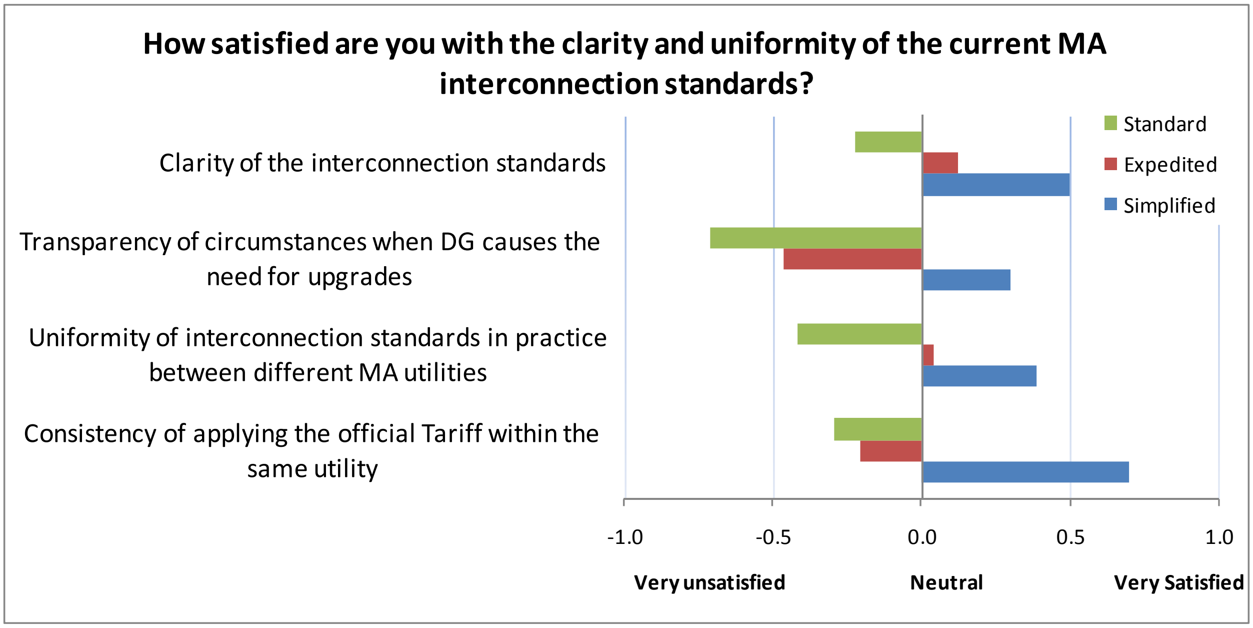
Figure 7-1 Importance of Interconnection Information: Applicant Views



Consistency across utilities – The survey specifically asked interconnection participants how satisfied they are with the clarity and uniformity of the current MA interconnection standards.

Survey participants who have only participated in the Simplified process are generally satisfied with the clarity and uniformity of the MA interconnection standards. However, participants who have experience in the Expedited or Standard procedures are much less satisfied in this category.

Figure 7-2 Consistency of DG Interconnection Standards: Applicant Views



Comments frequently pointed out instances where information or actions requested of them were unexpected, unjustified (in their view) or inconsistent with their previous experience, whether at the same utility or another. Many of the respondents choosing to keep their responses confidential made comments of this sort. Representative comments from those allowing us to quote their replies include:

- "The costs are arbitrary and not defined. They need to be standardized between utilities.…"
- "I will again come back to the [utility A vs. utility B] comparison, which shows a major cost difference. There needs to be some comparison among the utilities for more complex projects."

KEMA asked utility respondents whether they thought that "interconnection thresholds and approval standards are implemented uniformly across the MA utilities?" On a scale of 0 to 10, where 0 is defined as "no consistency" and 10 as "100% consistency across all four companies", interviewees rated the current level of consistency as 7.6. Nonetheless, there is recognition that consistency has slipped from the ideal. This has occurred under the pressure of higher application volumes for larger, more complex systems, each of which requires a solution tailored to its location, generation and protection requirements.

DG applicants perceive the variation in their interconnection experiences as an indication of inconsistency within the utilities' treatment of their applications. As pointed out in Section 3's discussion of process delays, DG applicants generally fail to appreciate the extent of site-specific tailoring to its grid location each DG interconnection requires. What appears to the industry as inconsistency may well be adherence to planning and technical rules of which the industry has limited knowledge or appreciation. Some utility staff would address this by requiring DG installers to attend interconnection workshops and/or be certified in a degree of system knowledge. Their understanding needs to go beyond completion of the application to include why the utility has different protection and interconnection requirements for different locations and different DG.

Alternative Dispute Resolution (ADR) process The MA Tariff contains a detailed section on dispute resolution; Section 9.0 pages 48-51. This provision of the Tariff spells out three levels of dispute resolution, from the most expeditious and informal ("Good Faith Negotiation", Section 9.1 in the Tariff) through the most formal, a full adjudicatory hearing process before the DPU (Section 9.3 "Departmental Adjudicatory Hearing"). The second step, spelled out in Section 9.2, provides for mediation and/or non-binding arbitration between the parties.

This study did not review the number of specific instances in which any of these levels have been utilized. The survey, however, did ask DG applicants for their views on the effectiveness of the current process. Most participants (54 0f 63 respondents, or 86%) found this question not applicable to their experience, suggesting that they have not utilized the process as defined. However, 14% (9) of respondents did respond. Of these, one third deemed the current process effective, while two-thirds did not.

Those familiar with the current process say it takes too long, causing still further delays to the project: "It takes MUCH too long and is WAY too burdensome." Parties already aggrieved by the length of a complex and expensive interconnection process have significant disincentive to delay their project still further by pursuing a formal DPU hearing. Other commenters see the process as too weighted toward the utilities – a majority of the survey comments expressed a variant of the concern that any complaint will cause their project to be further delayed.

Anecdotally, it has been suggested that the main value of the current process is that it exists – when both parties know they have the ability to escalate disputes to the DPU, there is an incentive to resolve issues expeditiously. A look at the final disposition of cases utilizing step one, Good Faith Negotiation would be prudent prior to any recommendations whether or how to change the present processes. Potential improvements might involve an Ombudsman, "fast track" or liaison role as alternatives to the current Mediation/Non-binding Arbitration.

7.2 Integration into Near-Term Planning

Establishing the value of DG – In 2004 the Massachusetts DTE requested the DG Collaborative to investigate the issue of "the role of DG in distribution planning." This led to substantial research and discussions from 2004 through 2009, including the following Attachments to the DG Collaboratives' June 2006 Report:

- Attachment G: DG and Distribution Planning: An Economic Analysis for the Massachusetts DG Collaborative;
- Attachment H: Report of the Distribution Planning Work Group on DG and Distribution Planning;
- Attachment I: Symposium on Technical and Business Challenges for DG to Play a Role in T&D Planning; and
- December 31, 2006 Update on Distributed Energy Planning Workshops, Submitted to DTE, with Attachment B: Guidance Document for Customer Owned Distributed Generation Applications, Table of Contents and Chapter 1.

In addition, the Massachusetts Technology Collaborative determined that the value of DG to the distribution system is dependent on the overall quantity of DG that becomes integrated into the system, which prompted the following research:

- Market Potential of Combined Heat and Power in Massachusetts, Prepared for Massachusetts Technology Collaborative, Pursuant to June 30, 2006 Report of the DG Collaborative, Prepared by KEMA, Inc., October 8, 2008.

The Division of Energy Resources participated in a US-DOE funded effort to consider business models for sharing benefits when DG might contribute to utilities deferring line upgrades:

- EPRI, "Creating Incentives for Electric Providers to Integrate Distributed Energy Resources," prepared for US-DOE, MA-DOER, and the California Energy Commission, November 2007.

Finally, the Collaborative identified the value DG could provide to utility customers regardless of location. The following research was undertaken to quantify this value:

- Synapse Energy Economics, Inc., “Impacts of Distributed Generation on Wholesale Electric Prices and Air Emissions in Massachusetts,” for Massachusetts Technology Collaborative, March 2008.

In the period since these studies were completed, technology has continued to develop. New sensor and communication and control technologies and new business models have been under development for the smart grid and for “non-wires solutions”, as noted by survey respondents. Thanks to work by the DG Collaborative through 2009, MA utilities and regulators have a foundation on which to build further understanding of the potential benefits and challenges of DG for distribution planners. This foundation gives MA a starting point to incorporate recent Smart Grid developments into a strategy that articulates the most effective integration of Smart Grid and DG investments. Within such an integrated planning framework, DG could take its rightful place as a legitimate component of a utility’s capital and distribution system planning and potentially a cornerstone of the future utility distribution business. As a result of identifying such least cost solutions, DG could move toward higher levels of penetration, bringing benefits that would be shared between ratepayers and customers installing DG.

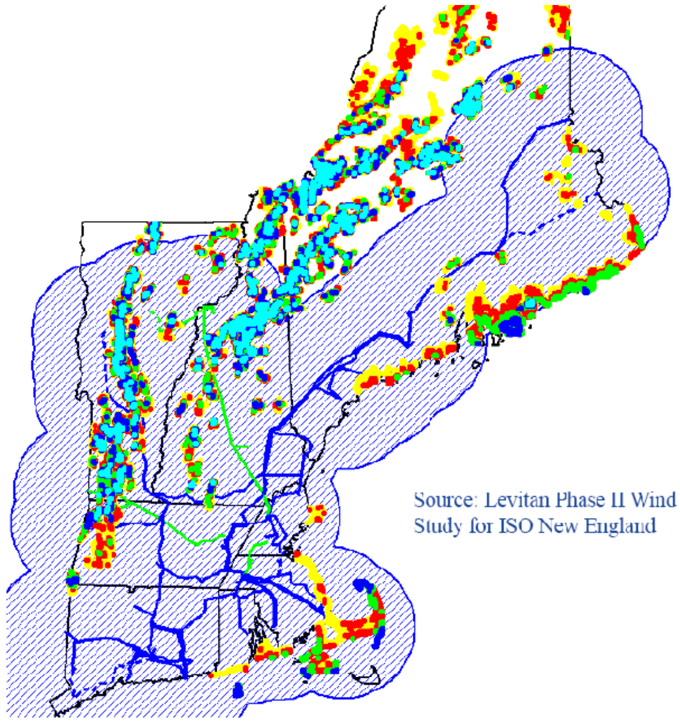
Such a strategy could, for example, identify ways to use some DG configurations to provide the equivalent of distribution capacity to avoid a utility’s need to charge DG customers fully for distribution/wires upgrades. Such a Smart-Grid-enabled DG strategy would offer multiple benefits for the DG interconnection process, by:

- Improving the alignment between utility system planning objectives and DG owner objectives;
- Increasing utility motivation to accelerate DG interconnection, at least in valuable locations;
- Identifying synergies between the utility’s Smart Grid plans and both current and future areas of high DG penetration (see next section), to inform and enable the planning for system upgrades that benefit both DG applicants and ratepayers as a whole; and
- Providing a regulatory basis to allocate the costs of system upgrades to the full range of beneficiaries, including ratepayers who would receive benefits from the integrated DG.

Survey Resource Availability – DG can be expected to be interconnected unevenly throughout the state depending on resource availability. Appropriate planning for the continued growth of these resources will take into account where DG resources are and their proximity to distribution lines. At the transmission level, ISO-NE has undertaken similar planning. Figure

7-3 below is taken from ISO-NE's study to identify potential wind resources by wind class, mapped against transmission lines.[98]

Figure 7-3 Wind Resource Proximity to Transmission Lines



The colored dots show wind classes throughout the state and the shaded parts show the areas that are within 40 miles of transmission lines. Based on information like this, the ISO will need to develop accurate intra-day and day-ahead wind power forecasts in order to ensure sufficient unit commitment and market operation. In addition, as wind penetration increases, the ISO will need tools to forecast wind ramping so that system operators can prepare for volatile wind situations by obtaining additional reserves or making other system adjustments.

As solar and wind penetration increases, operators of the local distribution system will also need to develop better resource forecasting capability. By constructing similar overlays of resources against areas of the distribution area, the MA utilities will be able to better anticipate areas where DG penetration is likely to increase most quickly.

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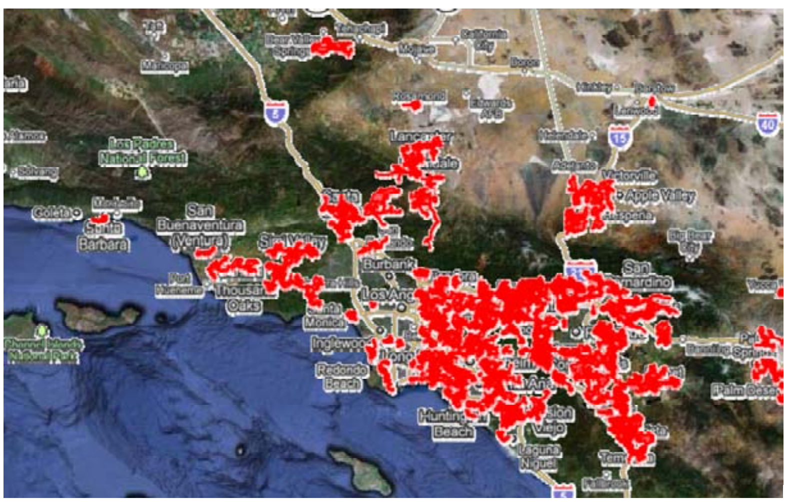
[98] ISO-NE, "New England Wind Integration Study", downloaded from: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/dec172008/a_wind.pdf

Mapping of favorable interconnection areas – Once utilities understand the impact of high penetration DG on the grid, where DG resources are and when they would likely come online, the next step is to overlay this information on a map that illustrates the most accommodating/robust areas for interconnection.

In California, Southern California Edison (SCE) uses interconnection maps to highlight and quantify the excess capacity on the grid. (See for example the maps available through the link below[99]). An applicant could potentially minimize the cost of interconnection to the SCE system by locating their projects inside one of the identified areas highlighted in the map. The SCE maps are provided publicly on its interconnection website to aid applicants to quickly identify interconnection areas. The maps use Google Earth technology to allow zooming and satellite views.

Figure 7-4 SCE Interconnection Map



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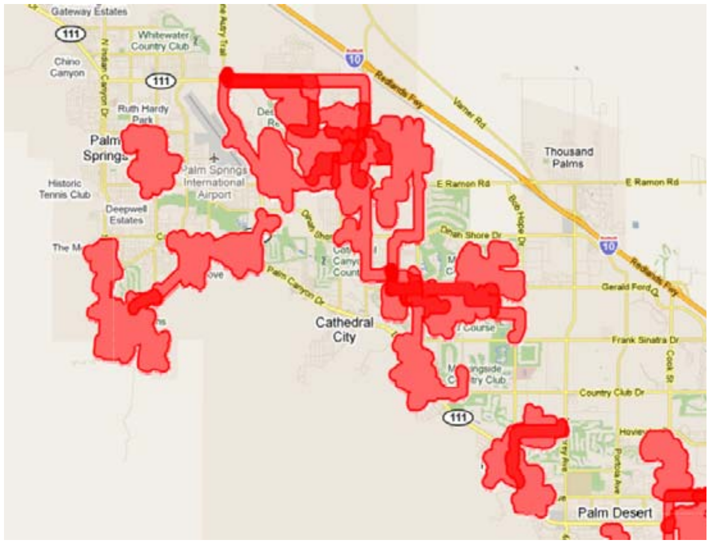
[99] Access SCE's Solar PV program maps through http://www.sce.com/EnergyProcurement/renewables/spvp-ipp/spvp-ipp.htm.

Figure 7-5 SCE Interconnection Map - Street-Level View



According to the SCE website each red shaded area on the map represents a circuit boundary on the distribution system. The areas show locations that SCE believes would give a high probability of passing the Fast Track interconnection screens (high load, low generation). It also includes SCE's approximation of available capacity for new solar PV generation at that location. It's important to note that the overlapping areas do not indicate higher capacity availability; rather, the colored sections indicate approximate boundaries of favorable interconnection areas.

The presentation of planning maps of this sort is of significant assistance to both the industry and the utilities in that it directs future interest toward areas that can most easily accommodate future DG. More jurisdictions are moving to require mapping of this sort;[100] MA utilities could build upon the excellent foundation of the Boston Solar Map[101] to do so as well.

7.3 Planning for High-Volume DG

As the MA distribution system has begun to see the advent of multiple DG on single feeders, it is prudent to look ahead to deeper penetration across the distribution grid. An understanding of

[100] For example, California's decision D.10-12-048 adopting the Renewable Auction Mechanism, also identified critical Market Elements (section 11) of the program, which includes section 11.1 "Preferred Locations to Facilitate Interconnections". This section sets the expectation of substation-level data from each IOU, initially in "preferred areas" and ultimately "over time..system wide". http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/128432-10.htm#P543_121326.

[101] The Boston Solar map is available at http://gis.cityofboston.gov/solarboston/

the impacts of high penetration DG will assist planners to anticipate local impacts. Several recent efforts provide insight for consideration by distribution system planners:

Wind integration studies – In 2009, the ISO-NE contracted a New England Wind Integration Study (NEWIS) to evaluate the operational impacts of five hypothetical large-scale wind-integration scenarios. The study identified a New England-specific wind climate regime based on historical weather data, to show wind patterns throughout the region. Then the study identified five wind-integration scenarios ranging from 1 to 12 GW of nameplate generating capacity. These scenarios produced wind energy ranging from 2.5% to 24% of total New England projected 2020 electricity demand, based on wind resources proposed in the ISO Generator Interconnection Queue (ISO queue). While this study only analyzed interconnections to the bulk transmission system, a similar analysis for on-site systems on the customer side of the meter could be useful. The study then modeled the effects of the pre-defined wind regime on the different scenarios. The study provided the following insights for distribution system planning:

- The region needs to maintain a flexible system. Such flexibility could be maintained by flexible sources, such as natural-gas fired generation or energy storage technologies, therefore supplemental payments for these flexible resources may increase.
- Since wind is primarily a winter-energy resource, the system would need to maintain adequate capacity resources to serve the summer peak demand, which typically coincides with reduced wind generation.
- Significant wind generation will increase the regulation capacity and operating reserve requirements.

DG simulation tools – Several utility respondents in KEMA's interviews voiced concerns about the availability of software tools and models adequate to the job of anticipating higher levels of DG penetration in the distribution system. In Germany, Spain and California, grid operators who study grid loading and voltage effects have used network calculation software, such as Siemen's PSS/E software, GE's PSLF software, DigSilent's PowerFactory software, and others.[102] Software of this sort is able to perform steady-state load-flow calculations and simulation of DG at the point of common coupling. Such network calculations model the existing grid components and their technical properties (i.e., rated current) as well as the

[102] In addition to those listed, other grid simulation and modeling tools are available, including offerings from ABB (GridView) and KEMA (Elektra).

technical data of the conventional and distributed generation plants. Simplified calculation methods are also available for performance factors that do not require the use of full power-flow models.

Voltage quality mitigation – One of the main challenges of high DG penetration is maintenance of voltage quality. For example, unpredictable environmental factors, such as cloud cover on solar panels or changes in wind speed, could rapidly change the output of a DG system and cause voltage swings. Germany revised their rules in 2010 to require all new generating units that connect to the medium- and low-voltage networks to contribute to specific network ancillary services, including:

- Reactive power control – This is a set-point control for voltage stability.
- Active power reduction – This is a remote set-point control by the distribution network operator for power generation limitation in case of network congestion or danger of power system collapse. Automatic reduction of active power generation is applied according to the power droop characteristic in situations of over-frequency.
- Dynamic grid support – The dynamic reactive power controller adjusts the reactive power output of the PV inverter in order to maintain a preset voltage limitation.

In "*Voltage Control in Distribution Systems with High Level PV-Penetration,*[103]" Stetz, Yan and Braun simulated these ancillary services to show that both static and reactive power supply methods are capable of reducing voltage magnitudes within a low voltage network. As a result, both can contribute to increasing distribution system absorption capacity for installed PV systems. However an even higher absorption capacity can be achieved by applying the dynamic voltage control approach. Compared to no reactive power provision, the absorption capacity of the low voltage network for PV systems could be more than doubled by using the dynamic voltage control approach.

7.4 Discussion of Potential Approaches

KEMA recommends that distribution utilities include DG in their distribution system planning efforts, in order to more proactively address the prospective rate of DG interconnection. By identifying where and when DG resources are available and their likely impact on the grid,

[103] T. Stetz, W. Yan, M. Braun. *Voltage Control in Distribution Systems with high Level PV-Penetration– Improving Absorption Capacity for PV Systems by Reactive Power Supply.* Kassel, Germany, 2010.

distribution utilities could consider changes to cost sharing formulas for required upgrades. They could also develop distribution designs for specific areas to ensure the ability to accommodate potentially high levels of DG. To this end, KEMA recommends MA utilities consider appropriate actions in the following areas:

Improve understanding of DG impacts – MA distribution utilities could review best practices and tools in DG integration planning as a step toward developing approaches applicable to their own situations. Potential impacts to investigate in each utility's specific planning and distribution system contexts include:

- DG system services. DG can provide significant benefit to the grid if appropriately sited and/or equipped with "utility-friendly" components (see Section 6). For example, in Germany a bonus is given to systems that have certain system service features such as supporting frequency stability by active power control, and supporting voltage stability by reactive power control. Utilities should make sure they understand these benefits in the context of their specific distribution system and consider incentivizing DG accordingly.
- High-volume impacts. The interaction between different DG technologies interconnected in close proximity. To tackle proactively an issue expected to arise soon in some areas, MA utilities should start working now to better understand the interactions of different DG technologies interconnected in close proximity.
- Mapping desirable interconnection areas. Information on areas that support the fastest and least costly interconnection came out near the top of survey respondents' list of requests. The utilities should publish distribution maps that show where the distribution system has either adequate capacity or where additional DG might add distribution support. The maps should also show where the distribution lines are such that developers can plan the system type and size according.

Set and plan for the future target – The Commonwealth has aggressive objectives for the DG industry. Yet the current system is already under strain. To reach these targets, therefore, planning must begin to identify the implications of higher DG volumes statewide. The Commission should initiate a planning process that a) sets DG penetration levels at least consistent with current MW targets; b) identifies areas in the state where this growth is most likely to occur; c) examines the implications of those growth levels for utility distribution planning; and d) articulates the costs – to the utility, the DG industry and the rate-payers – of not planning adequately for this growth. Specific issues to examine include:

- Resources forecasting. Prospectively identifying the areas where DG resources are likely to be exploited can enable advanced planning of distribution system upgrades. Key load area substations may incorporate data acquisition and information storage and communications. Load and DG generation forecasters could then build new models that reflect the net load for the area. These models must include weather data, including temperature, wind speed and solar irradiance for the area.
- Protection regimes. Utilities would be well-advised to examine the implications of continued high-volume DG penetration for their protection planning processes. The integration of grid simulation tools into project review is a necessary step as applications and projects get more complex. The use of these tools to look beyond local impacts to single feeders and across wider areas of the system will be an important component of ensuring that protection remains adequate for the system as a whole.

Encourage voluntary improvements – The utilities already conduct regular interconnection workshops and have resumed monthly reporting of interconnection status. These voluntary activities should continue. In addition, we hope that the utilities will give full support and participation to any resumption of the DG Collaborative or similar vehicle for continued discussion of process improvements (see Section 8.3 for specific recommendations appropriate for collaborative work).

8. Summary and Recommendations

8.1 Summary of Key Findings

The overall story of DG interconnection in MA in 2011 contains a lot of good news. The industry is growing. The present process has worked very well up to this point. Among the key findings of this analysis are the following:

Mutual awareness and understanding – The survey results show that DG applicants and utilities have significantly different issues, priorities and levels of understanding about much of the interconnection process. In general, DG applicants are considerably less aware of utility operational and planning constraints than are the utilities of the applicants' concerns. This lack of mutual understanding exacerbates mutual suspicion and distrust. Many survey comments voiced applicant frustration that might well be reduced through greater understanding of the operating constraints facing the utility.

Application volume – The volume of DG applications in Massachusetts has increased sharply. Continued growth is likely, as long as current DG-friendly policies remain in place. Highlights of this growth:

- Total volume of interconnection applications grew four-fold for National Grid and NSTAR between 2004 and 2010.
- Starting in 2009, the increase in PV installations has had significant implications for the total volume of interconnection applications. The majority of the PV interconnection applications tracked were reviewed under the Expedited path[104] (see Section 4 and particularly Figure 4-1).
- Wind applications in 2009-2010 also grew significantly, and played a large part in the jump in total installed KW over this period. The majority of these projects were reviewed under the Standard process.
- The total KW volume of interconnection applications reviewed by either the Expedited or Standard path has grown seven-fold over the years between 2004 and 2010.

[104] We note that this statement refers to the number of "applications tracked" because the total number of applications, inclusive of Simplified applications, was not available in the data set for all years. Figures 4-1 through 4-3 cover Expedited and Standard applications only.

Application tracking and review – The current review process, while lauded for its successes in years past, is no longer up to the demands of the current application volume. The Simplified path is successful; applicants wish the other two tracks shared more of its attributes:

- *Simplified Review Process* – Applicants appreciate the Simplified review process. Survey results and comments show that applicants find both the review period and the costs of this path to be satisfactory. Utility personnel expressed a concern with the lack of fees for this process.
- *Time Frames* – Applicants express significant dissatisfaction with the overall time period required for completion of application reviews under both the Expedited and Standard review processes. In the eyes of survey respondents, the average reasonable time frames for these reviews should be 30 and 60 days respectively.
    - A very high percentage of Expedited and Standard reviews appear to be missing the Maximum Time Frames by a significant amount. This was particularly true in 2009, which may be attributable to a significant increase in applications from larger renewable DG projects. Many of these applications presented complications not previously experienced on the state's distribution systems (such as generation in excess of load).
    - There is currently no penalty for exceeding the Maximum Time Frames in the Tariff. There is no consequence to the utilities for delays, even though there are consequences – often significant – to the DG applicants. At present, use of the ADR process appears to be the only recourse and potential penalty, although it is rarely used and perceived to be just as much a penalty to the developer as the utility.
- *Tracking and Reporting* – The current tracking of interconnection application review times is insufficiently precise to be meaningful.
    - There is no data or process with which to verify or otherwise correct reported review periods for the periods of delay (for whatever reason) that occur within the reported application review period. See Section 4.4.

Interconnection costs – The costs of the interconnection process come in multiple forms. While the fees themselves are not considered burdensome, the total costs of interconnection cause frustration to both applicants and utilities.

- *Application Fees* – Current application fees are deemed satisfactory by most applicants for all review paths. Costs for the witness tests are satisfactory; applicants are neutral regarding costs for the Supplemental Review. Utility personnel stated that the fees do not cover their costs (other than those steps where actual cost is passed through to the DG customer).

- *Costs of Upgrades and Interconnection Equipment* – Applicants are generally dissatisfied with the costs of the interconnection equipment required to interconnect their projects. They are also dissatisfied with the cost of the facilities upgrades required for interconnection.

Secondary distribution networks – Massachusetts already allows some DG to interconnect in spot networks via the Simplified Spot Network path. The experience of applicants seeking interconnection into area networks has been more disappointing. Experience of PV interconnection into both spot and area networks is accumulating, however, and technologies like DCI provides a platform from which to reexamine the current practice in Massachusetts. Many observers think the Commonwealth should join other states that allow DG to interconnect into spot and area networks, within guidelines and conditions that respect the technical limitations of those networks.

- Inverter-based DG, in applications where DG output is significantly and reliably less than minimum facility load, should be reviewed for interconnection in area as well as spot networks. Conditions and requirements such as those discussed in Section 6 may be required but should not impede these approvals.
- Dynamic Controlled Inverters (DCI) and other "utility friendly" features should be incorporated into systems intended for interconnection in any secondary network. Utility distribution system impact modeling should become familiar with these features and the impact of DG that incorporates them.
- The DG Collaborative should reevaluate the current communications protocol in use with applicants seeking interconnection in secondary networks (Section 6.1.1). Clearer system sizing guidelines and/or component recommendations should enable these applicants to consider options that are not currently presented to them.
- IEEE P1547.6 has passed its initial balloting and is expected in final form by the end of 2011. When this standard is final, the DG Collaborative should reconvene to look at its implications for the growth of DG in the regions of MA served by spot and area networks.

State and Federal jurisdiction – The division of State and Federal jurisdiction appears generally workable to the MA utilities, although there is only a limited body of experience thus far, as not all MA utilities have seen their first ISO-NE jurisdictional project. In addition, Massachusetts' experience with the 2006 ISO-NE small generator review process is still limited:

- The larger utilities have separate transmission groups to handle these relations with the ISO; the smaller utilities may not have had any FERC-jurisdictional applications yet.
- The industry is confused about the demarcation between Federal and State review of DG applications. This confusion is particularly understandable in light of the fact, as discussed by the DG Collaborative and reported in Section 5, that there are three separate interconnection processes now in place – the MA Model Tariff, the ISO-NE administered FERC process, and a separate process governing QFs.[105]
- Applicants appear under-informed about FERC's potential role in both their interconnection decisions and subsequent power sales (i.e., through rules governing capacity payments and forward capacity markets).

Transparency, value and near-term planning – As the rate of DG applications continues to grow, utilities are faced with questions about how to respond.

- Transparency of both the process steps and the decision criteria used in those steps could be improved in many parts of the interconnection review process. Survey comments regarding on-line site information, tracking and mapping tools attest to the need for this information.
- The value of DG to the utility system has been established previously, through the work of the DG Collaborative. Industry observers wonder that utilities have not taken into account the benefit that carefully sited DG could represent, were utility planning processes to better anticipate and even encourage this growth.

8.2 Implications of the Findings

The imperative for change in the DG interconnection review process is now crystal clear. Industry demand for interconnections has outstripped the utilities' current capacity to provide those reviews in a manner that is timely, thorough and protective of the system integrity that is their highest obligation. The DG and utility industries, aided by regulators and policy-makers, must begin planning now to alleviate the bottleneck of the current interconnection process on continued growth in DG. To avoid impeding the industry's growth and/or sending DG developers to other states because they cannot afford the wait to interconnect in MA, today's

[105] As explained in Section 5, the three processes to which the DG Collaborative's referred in its 2006 annual report (and quoted on pages 72-73 are: a) the State's process, b) the Federal process through ISO-NE, and c) the separate process required of Qualifying Facilities (QFs), which is not reviewed in this report.

interconnection processes must leapfrog ahead. The objective: to design an interconnection process that is as close to 'frictionless' as possible.

The current review process is both resource and time constrained. To rethink these limitations requires thinking "outside the box" in two important areas: staffing levels and process re-engineering.

8.2.1 Staffing and Organization

The Massachusetts utilities vary significantly in service area size, volume of DG applications and therefore in the challenges of responding to that volume. All four have created a central point of contact for DG applicants, whether that point is a dedicated DG group, a general customer service organization, or a subgroup dedicated to DG. That point of contact often serves as an "account executive," shepherding the application through other departments involved in the review, studies and approval. Coordination with the applicant is usually channeled through that account executive, who relays requests for information and/or utility responses back to the customer. While Simplified applications may be handled at the point of customer contact (especially if this is a group dedicated to DG support), virtually all Expedited and Standard applications are reviewed by groups responsible for distribution system planning /engineering and protection at a minimum.

Once approved, all applications are handled by a metering group (in the district where the interconnection will occur) and a customer order fulfillment organization. The four utilities have from five to fourteen groups or departments involved in the handling of the more complex DG applications. Notably, in virtually all instances described by utility interviewees, these organizations are not dedicated to DG only. Rather, they must complete time-sensitive DG reviews concurrently with their responsibilities to all other utility customers.

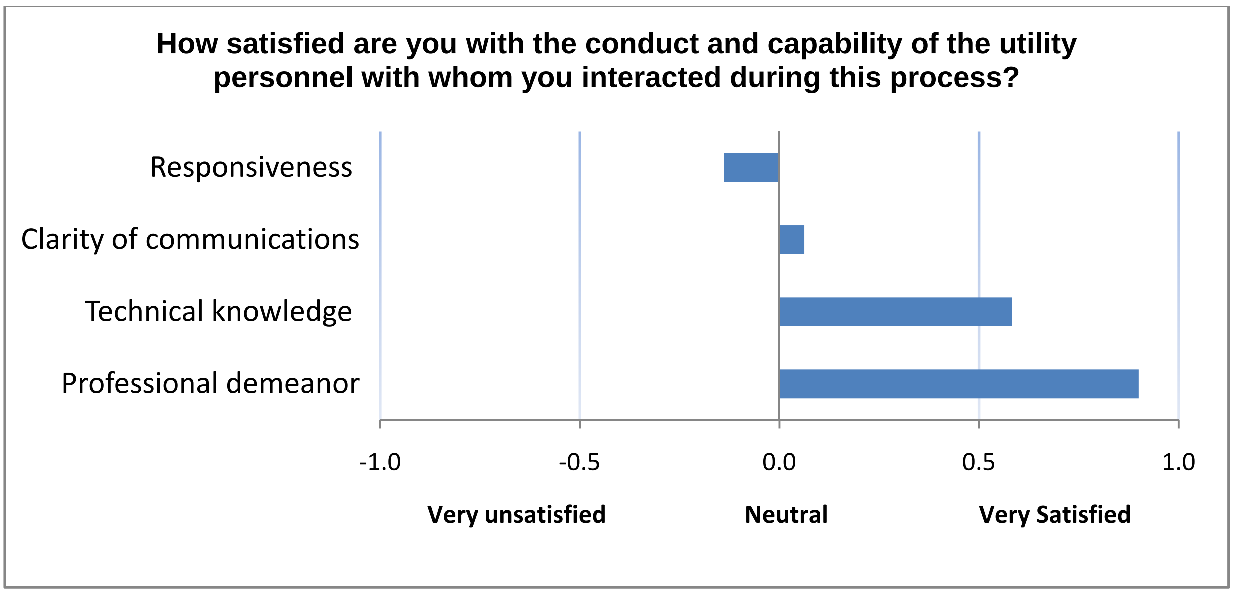
The majority of the MA utilities voiced concern about the pressures on staff created by the present DG volume. Looking at the likely volume two years into the future, 100% of respondents reported that staffing must increase by factors of 1.5 – 3 X. Pressures on staff today, especially in those utilities with high DG volume, are already considerable:

> "We need many more resources available, to give us the ability to respond faster. I have so many projects, I am systems planner for [region] and I am responsible for all customers, not just DG. In my region there are also major transmission projects, substation development projects and other customer-initiated projects going on, as well as DG."

“(My wish is) to have no other work conflict with the DG work. It absolutely is possible for a review to be done poorly, and as well the quality of the other work we’re doing can slip, so that other customers can be affected… the nightmare scenario is someone gets hurt from an islanding scenario….that affects more than the circuit where it’s located….”

The challenges of responding to the volume of DG work are visible to DG applicants as well as utility staff. Recall that “Utility staffing constraints” was essentially tied with internal utility communications delays as the most important contributing reason for process delays (Figure 4-15). The survey asked a general question about overall satisfaction with utility personnel (Figure 8-1). Applicants applaud the professional demeanor of utility staff and are generally satisfied with the level of technical competence they encountered. Yet they registered dissatisfaction with the timeliness and responsiveness of that communication.

Figure 8-1 DG Applicant Views of Utility Staff



Survey comments showed a similar spread. Some comments singled out individuals for applause (e.g. “I commend Cindy Janke at NU”); others described less salutary experiences (e.g. “Each process involved a mix of exemplary individuals doing a great job and specific individuals with whom there were problems”) and others acknowledged the very real constraints impinging on utility staff:

“I also acknowledge that the DG department at my utility is probably overwhelmed with the number of applications received”.

“…Too busy due to so many new DG applications.. we are told that the utilities are swamped due to under-staffing of various departments. They said that the number of applications jumped from a dozen to several hundred last year.”

KEMA observes that the interactive effect of staffing constraints and competing responsibilities contributes significantly to the challenge of timely DG review. Our interviews suggest that utility staff are caught between the proverbial rock and hard place – the demands of a hierarchical organizational structure accustomed to sequential decision-making across multiple technical specialties, and the demands of myriad customers clamoring for concurrent review of multiple time-sensitive yet technically complex interconnection proposals.

One element of the long-term solution must be, as mentioned by several utility interviewees, work redesign of the DG review process. In concert with changes to the application process and information flow described elsewhere, utilities may find it useful consider several possible work designs. One is described next, as it is in use to some degree; other possibilities are introduced in the following section.

Some utilities utilize a dedicated DG group for customer contact and DG coordination. In this structure, DG studies are assigned to other groups e.g., distribution engineering, protection, etc. As DG application volume grows, DG groups may be prudent to add their own distribution- and protection- engineers. Doing so will enable the DG group to gain depth rapidly, as they review a wider array of applications, settings, etc. A dedicated group is also able to maintain sole focus on the completion of high-quality reviews within the time targets, and never lose time for non-DG priorities. Several utility interviewees expressed a wish for this degree of focus and staff resource to DG work:

“….These are all within the engineering group.. (we have) a total of [X] staff however this group does the engineering for (other areas) as well, so maybe [1/3 X] total get involved for the projects in this region…. Ultimately, I’d love to have a dedicated DG group….”

“We need a separate DG organization, a group of [2X] – we have [X] now but they can only spend 10-25% of their time on DG. We need much more capability and time from those resources, and we need them dedicated to this work so they can be trained on all the variations and get more efficient….”

In the final analysis, the utilities’ ability to process DG applications in an efficient, timely, and above all high-quality manner depends on the quantity, quality and ability of the staff assigned to these roles. The demands of today’s DG volume have already placed staff in most utilities under significant stress. Given the steadily increasing volume, the decentralized structure – where DG responsibilities compete with non-DG obligations – can place significant pressure on reviewers, review times and potentially review quality. Utility managers should monitor staffing levels closely to ensure that metrics are met for both quality and volume, without burning out the experienced staff upon which these quality reviews depend.

8.2.2 Potential Process Design Improvements

KEMA's interviews with utility staff posed several different process changes. Each concept was intended to remove process time from some aspect of the current interconnection review process. We summarize the comments on each concept below, in the order of their support among utility staff:

- **Pre-application consultation** – Most utility respondents joined survey respondents in scoring this option favorably – one said: "(I'd give this option) One million points – this would help a lot." Others are more skeptical, judging the value of a pre-meeting more limited because a) applicant plans may still evolve post-meeting; and b) efficiencies in the application process don't shorten the time required for engineering review.

- **On-line Interconnection application** – Some MA utilities already use elements of an online application process for the Simplified process and acknowledge that it has helped streamline the process. Others express doubt that the online submission would improve the review for Expedited and Standard applications, since information is already exchanged via email.[106] In the eyes of one respondent: "….an online application would have to be interactive – it would be a huge improvement from today – that alone would be a huge step in the right direction."

- **Applicant-paid engineering contractors** – The use of utility-screened consulting engineers to add engineering review capacity also generated mixed reactions from utility staff. Concerns ranged from a) the confidentiality of utility models and customer data; b) lack of suitable talent available; and c) no cost-savings to the applicant, who pays the study cost whether performed by utility staff or consultants. If these concerns were handled, however, several respondents noted that this added capacity would enable the study steps to be completed concurrently, thereby cutting time from the process.

[106] We discuss the other features and advantages of an online application tool in Section 4.

- **Technology-differentiated screens and timelines** – One utility respondent reported that their company had already implemented this solution to some extent. Others see the potential to streamline the processes for specific technologies like PV or other inverter-based DG.

- **Map of DG-related information** – The utility respondents split on this concept. 50% were strongly supportive, reporting that it would streamline the process if DG applicants could learn immediately the nature of the circuits they've targeted, the protection components in place, any pre-existing DG on the line, and therefore the study and timing requirements likely to be required. Others reported that they already provide this information upon request, and that the requirement to update the map frequently would offset its benefits.

- **"Batched" application process** – Batching DG applications adds efficiency only where volumes are high enough to allow batching by feeder, DG type or approval path (e.g., Expedited). Review by batch also implies that the application most easily approved would be held to the timetable of any in the batch requiring further study. This delay might be acceptable to delayed applicants if the accompanying cost allocation formula was sufficiently advantageous to compensate. Utilities might begin to develop the cost allocation formula for studies that affect multiple applicants seeking interconnection on the same feeder. Such guidelines should address what happens if — midway through the study — one applicant drops out.

- **Auction for guaranteed review period** – Under this concept, each utility would commit to completing the review of a fixed number of standard applications on a known and guaranteed timeline, and auction those slots. Auction proceeds would be used to ensure the staff and/or consulting resources needed by the utility to meet its guaranteed date. Few utility respondents felt able to comment on this option; the one who did, however, was strongly supportive, on the basis of the work load predictability that such a process would provide.

In summary, the meta-message of this report rests at the intersection of several trends. Massachusetts has created a vibrant policy environment for DG, underpinned by one of the best interconnection processes in the country, a process which has generally worked well for most DG applicants since its introduction in 2004. Over the last seven years, however, and particularly under the Patrick Administration, the growth in DG volume has grown significantly.

Yet, our survey showed that 79% of Expedited applicants and 75% of Standard applicants are “Somewhat dissatisfied” or “Very dissatisfied” with a process they describe as long, inconsistent, and “too complicated to comment”. By contrast, the process works well for Simplified applicants, only 4% of whom described themselves as dissatisfied. Their experience is quick, transparent and almost entirely satisfactory.

We define a successful process as one that meets its customer demand with high quality outcomes, within acceptable parameters of time and cost. This review demonstrates that – seven years after its introduction – the current process by which DG is interconnected in Massachusetts is no longer meeting the demands of three-quarters of its customers.

8.3 Recommendations

This study has assembled an updated review of several topics of concern to the MA DG industry, while adding to that review important data capturing the views, issues and desires of the DG applicants surveyed and the utilities. Because of the timeframe and study constraints involved, this report does not represent that all issues have been explored in the depth they might otherwise warrant. Similarly, the “recommendations” listed below have not been vetted with either the utilities or the wider stakeholder community; they represent the views of the project study team only.

These recommendations do, however, constitute a preliminary set of actions that, if taken, could generate movement toward the outcomes sought by industry and utilities alike – a swiftly efficient and effective DG interconnection planning, review and approval process, one that protects customer safety and system integrity, while moving toward a world where DG continues to play an increasingly important role in meeting the energy needs of the Commonwealth.

High Priority

1.0 Charge DOER to reconvene the DG Collaborative. The Commission should charter the DG Collaborative to play an important role in the work ahead, to revamp the DG interconnection process. The Commission should also charge DOER to convene, manage and support the Collaborative through the tasks assigned to it (see Recommendation 6).

2.0 Require additional utility information. The Commission should request the following information from the regulated utilities, through the mode identified:

2.1 *In the required monthly utility reporting*, the following additional information:

- The duration of any suspension periods in all interconnection proceedings, by applicant. This data is needed to correct current process durations such that the real length of each step can be determined.
- The names of all applicants in any step of the dispute resolution process.

2.2 *A one-time data request,* to include:

- Most common upgrades required of DG applicants, by project size, type, location and cost in the last two years. This data will inform the Workshops regarding the 'most common upgrades' and thereby help set applicant expectations;
- Each type of study/ review currently conducted by the utility; and its average duration under present staffing levels.
- Publication of the decision standards for each current review screen and the engineering criteria for requiring upgrades, per Section 4.3 of this report; and
- Identification and to the extent possible quantification of the "interactive effects" between DG units on same feeders/ circuits for which the utilities have the greatest technical concerns, and the basis for those concerns, citing examples.

3.0 Initiate a proceeding on Interconnection Application Process Redesign – The design of this process is critical to resolving the current impasse between application volume and review completion. The process should include the following elements:

3.1 *Pre-Application "Informational Briefing"* – Several utilities offer this service today; those that do applaud its usefulness to both applicant and the review process. Strongly recommend this practice to all applicants, to the point of charging an application surcharge if applicants don't attend prior to submitting their application. Mandate attendance for identified categories of applications, as specified in the application tool.

3.2 *Stakeholder and Utility Participation* – Require participation by utilities[107] (inviting the municipal utilities as well), MA agencies and open to DG stakeholders (customers and developers);

3.3 *Timeline for the new process* – Set a timeline for realizing the objective of an on-line interconnection application tool for statewide use. Consider an expedited timeline, such as the following:

- Objectives and tool design specifications to be completed no later than 12/31/2011;
- RFP for software design in January 2012; and
- Application system available for trial testing by 7/1/2012.

3.4 *Process design principles* – These principles /design objectives for this tool, and the specific functions to be incorporated, should be the specific focus of a DPU process. This process *may* have collaborative aspects – including facilitation – but should not be confined to a consensus-based process/timeline. The design principles should include such things as:

- *Data integration and confidentiality* – Integration with utility databases in a manner that protects the integrity and confidentiality of utility customer data.
- *"No surprises"* – This is the standard to which applicants should be educated by the time they begin the application process. Through the Workshops, system details posted by the utilities and the pre-application briefing, this new process is being designed to ensure that no applicant is surprised at any step.
- *Complete information at every step* – Ensure that the review process starts each step with all relevant information or that step does not start at all.
- *Applicant commitment* statement – Upon submission of the completed information for each phase of the application, the applicant will be asked to sign off on it as the basis for the utility's review, along the lines of:

[107] The utilities have expressed concern that this process could add to their already constrained personnel resources. The process could allow utility representative to coordinate their participation on a rotating basis, as long as one of the four IOUs was in attendance at all scheduled meetings.

"There are no intentions to change any substantive elements of the project as of this submission date. I understand that any change(s) that materially increase[108] the project's impact on the distribution system may substantively alter the review process, thereby triggering the need for a new application; lengthening the review process and/or materially changing the cost of both the review and any needed upgrades."

- *Benchmarked process steps* – The system must have the ability to automatically track each process step, from completed on-line submittal of information, through the review steps completed by each utility.
- *Binding Utility Review Periods* – Once the new system is in place, the utilities should expect that penalties will be assessed for review periods that extend beyond the benchmarked time periods.
- *Exceptions for the "Pioneering" projects only* – The system should enable the override of time periods only under rare and specific conditions, generally reserved for "first time" projects. The specific features that allow the 'first time exception' should be addressed; otherwise, all parties should understand that – once the benchmarked time periods are set – the time clock will track actual completion periods.

3.5 Specific functions and features to be included:

- *Step-wise Process* – On-line application process consisting of several application steps, the first of which (i.e., project type, size, site location(s) review) are not binding and carry no fee. (See Recommendation 5.4)
- *Interconnection Mapping Tool* – This tool will alert developers of both the characteristics of the distribution feeder into which they might interconnect, and of the review process they will encounter, based on the specific characteristics of their projected location(s). Minimum information to include:
    - Location of area and spot networks;
    - FERC jurisdictional lines;
    - Substation capacities;

[108] Changes that decrease the size and/or impact of the project on the distribution system or that are otherwise requested by the utility constitute "no penalty changes".

- Levels of existing DG penetration and levels of DG capacity that can be interconnected under the current protection regime; and
  - Location/penetration of Smart Grid components.

- *Mandatory Fields/ Attachments* – This information needs to be established for each stage of the review process, according to the requirements of the applicants' location and project. These fields define when the application is ready for the next stage. Required information is determined from the utility's database, using system and location information entered by the applicant in the first few screens.

- *Redefined Date Fields* – The date fields enable the time clock to begin only when the information required for each stage of the review process has been provided and the package accepted as complete.

- *Automatic Tracking Metrics* – The functions recommended in this tool result in a fully complete information package at the start of each review stage, thereby enabling a clear start date. End dates will be similarly noted upon completion of each stage; the time tracking does not stop, except under extraordinary conditions (e.g., "Pioneering projects").

4.0 Open a Notice of Inquiry: Planning for High-Volume DG Penetration – This NOI could be opened concurrent with the Application redesign effort, although doing so might exacerbate concerns about constrained utility personnel. Through a structured NOI process, invite utility input, testimony and potential participation in discussions of the following issues:

- *Process constraints* – What a) factors most constrain utilities' current ability to meet the Maximum Timeframes in the MA Model Tariff; b) what plans do the utilities have to address their current difficulty meeting those timelines; and c) what would be the appropriate components of a "DG Performance Score"?

- *Technical constraints* What components, technologies and/or specific devices most constrain each feeder's ability to accommodate increasing levels of DG output;

- *Upgrade priorities* – What areas (circuits, feeders, neighborhoods) of the current grid should be prioritized for upgrade over others, and why;

- *Planning for RPS success* – What steps would each utility need to implement and over what time period to meet the targets under the Green Communities Act[109], assuming DG adoption rates stay on track to meet the statutory targets and that each utility retains its current share of the annual total DG applications; and
- *Performance metrics* – What systems of interconnection-related incentives and penalties should be incorporated into the existing metrics for service quality and distribution system planning, to ensure that interconnection timelines are met and to encourage utility investment in the upgrades needed for high-penetration DG.

Next Priority

5.0 Fix the Dispute Resolution (DR) process – The current DR process in the MA Model Tariff is very formal, cumbersome, expensive and slow. To help resolve issues faster, we recommend that the DPU name a staff DG Ombudsman:

5.1 *Ombudsman role* – The Ombudsman would hear – in confidence – the complaints of parties that reach the end of Step 9.1 Good Faith Negotiation without resolution. The Ombudsman would a) be easily accessible; b) review the written documentation from Step 9.1; c) conduct independent interviews/ investigations as deemed necessary; d) offer independent problem-solving assistance from a third-party vantage.

5.2 *Ombudsman's judgments* – The intent of the Ombudsman is to resolve issues as expeditiously as possible. The Ombudsman could a) propose a solution (non-binding); b) render a judgment about whether the issues are best resolved through i) an informal settlement; ii) other alternative means (e.g., informal negotiation before an expert third party); or iii) continued use of the DR process. If the latter, the Ombudsman could also advise whether the dispute should pursue Step 9.2 Mediation/ Informal Arbitration, or go directly to 9.3 Departmental Hearing.

[109] See footnote #1.

6.0 Reconvene the DG Collaborative. DOER should convene, chair, host and support the Collaborative, and ensure that appropriate facilitation is provided to enable the group to accomplish the tasks below. The Collaborative should serve in an advisory capacity for a finite period, under deadlines to accomplish the specific tasks listed below. The Collaborative's first task would be to create – within its first month of meeting – the timelines it will follow to complete the following tasks:

6.1 *Update the Simplified Path* – Review current thresholds in the MA Tariff for the Simplified process, to determine appropriate changes and recommend these for DPU consideration. This review should specifically include an examination of the Vermont registration process for its potential applicability to MA.[110]

6.2 *Review the Expedited Process* – Recommend specific changes to the thresholds and screens for the Expedited process, with the objective of expanding Expedited review to more applicants, consistent with utility requirements for safety and reliability. This step may include the creation of new screens to address:

- Whether DG will be exporting and if so, whether into wholesale markets;
- Whether the applicant is the first DG greater than 2 MW on the circuit; and
- The potential for seasonal limits on an imbalance between output and load on low-load lines.

6.3 *Update the Interconnection workshops* – Identify additional and modified content in the utility-offered Interconnection workshops, and distinguish between material appropriate for a Basic versus Advanced level workshop. Material to include:

- The major safety, reliability and operating rules in place on the local distribution system(s);
- The differences in protection regimes already in place, the decision criteria for when these are required, and the typical costs for upgrades when needed;

[110] Vermont's solar registration law. See http://www.pv-tech.org/news/vermont_enacts_new_law_that_streamlines_solar_pv_registration_process_to_he

- The demarcation between State- and Federal jurisdiction, what triggers it and 'managing the ISO queue' (Advanced) and
- Any other information that will assist DG applicants in anticipating the specific technical study/ modification requirements their applications might encounter.

6.4 *Create a Stepwise Framework for the (revamped) Application Review Process* – The inclusive setting of the DG Collaborative – if facilitated – is the right place to reconcile the applicants' desire for shorter steps with the utilities' need for care. This framework of steps resulting from this process will set the stage for the electronic development process to follow (See Recommendation 3.0).

- This framework should include all steps in the process, from application through energizing the system, regardless of who takes the step;
- The framework should also identify a) what criteria determine when each step is complete; and b) what information is needed at that step;
- The framework should not address either a) time expectations for each stage/ step, b) quality standards or c) penalties. (See Recommendation 4.0)

7.0 "Getting Connected": DG Interconnection Education Campaign – The KEMA survey revealed a significant level of misinformation among the applicants regarding the requirements to interconnect their projects safely into the distribution system. The current workshops will be bolstered in Recommendation 1.3. Under the leadership of DOER, all parties – utilities, DG advocates and trade associations, customers and other industry participants – should make it a priority to understand fully all the content in these workshops.

7.1 *Interconnection Workshops* – Of all the information sources available to applicants, they rated the informational workshops the most highly. The existing schedule of workshops might need to be enlarged, in light of a) the new Advanced sessions; b) the potential requirement that specific application sizes/ types be strongly encouraged to attend (e.g., through fee surcharge if not).

7.2 *Distribution System Maps* – Voluntarily if possible or under order if not, the utilities should identify and provide as possible the information needed to begin the interconnection application process. This includes: the boundaries of their current distribution systems (noting all networks), 13 kV lines and their interconnection limitations, and output and load on low load lines.

8.0 Federal-State Coordination – DOER should take the lead to address the issues of ambiguity in the relationship between the Commonwealth and the ISO as they affect the DG interconnection process. These steps should include:

8.1 *Convene a multi-state working group* – DOER should extend an invitation to the energy offices of the other New England states to work collectively to clarify issues that may be affecting them as well. This "group of the willing" should work collaboratively with ISO-NE to sort out some of the questions raised in this study.

8.2 *Develop guidance for Interconnection applicants* – This guidance should address a) the jurisdictional 'gray areas' and questions of definition raised in Section 5, b) develop procedures for the transfer of lead responsibility and information/studies in progress when jurisdiction is deemed to have changed mid-review; and c) develop general workshop content regarding the ISO-NE 'queue' and its implications for interconnection applications.

9.0 Network Interconnections (Section 6) – Once passed, IEEE P1547.6 will likely open additional possibilities for action on this issue:

9.1 *IEEE 1547.6's implications for MA* – DOER should reconvene the DG Collaborative to consider the implications of IEEE 1547.6's guidance vis a vis spot and area networks. Determine whether the current standard letter to area network applicants is still appropriate given both this guidance and the increasing availability of more 'network-friendly' components for inverter-based DG.

9.2 *Research the European experience with networks* – Interconnection of DG into area networks is more common in European experience. Depending upon the extent to which IEEE 1547.6 provides workable guidance, DOER should research the differences between European and MA area interconnection approaches.

9.3 *Enhance Network Monitoring* – Follow the results of NSTAR's work on network visibility and DG integration. To the extent warranted, add visibility to the secondary distribution network in other areas.

10.0 Organization and Staffing (Section 8.2) – The pressures of increased DG volume, finite staff and conflicting priorities have placed considerable pressure on utility staff. So much so that applicants cite these constraints as a source of delay equal to the communications challenges that currently typify the process. The following steps are recommended for the utilities' consideration:

10.1 *DG Interconnection metrics* – With the implementation of Recommendations 3 and 4, significant inefficiencies should be removed from the current application and review processes. Between now and then, however, utilities face continued growth in the backlog of DG applications. Utilities should set and publicize to applicants their own performance metrics – timelines they CAN meet, if not the current MA Tariff targets. The Commission, through the proceeding in Recommendation 4, will have an opportunity to accept, reject or otherwise express itself on the appropriateness of these metrics.

10.2 *Internal process redesign* – Utility interviewees favor use of a dedicated group to specialize in the DG review process. Doing so has advantages in terms of shortening communications pathways and allowing expertise to accumulate in that group over time. The organizational changes discussed in Section 8.2 are intended to broaden the slate of options for utility consideration. Utilities need to make sure that their staffing levels and internal processes are adequate to meet the a) the metrics they set for themselves (above) and b) the metrics incorporated into their levels of service metrics (per Recommendation 4.0)

A. Appendix A – MA Model Interconnection Tariff (Excerpts)

Figure 1 – Schematic of Massachusetts DG Interconnection Process

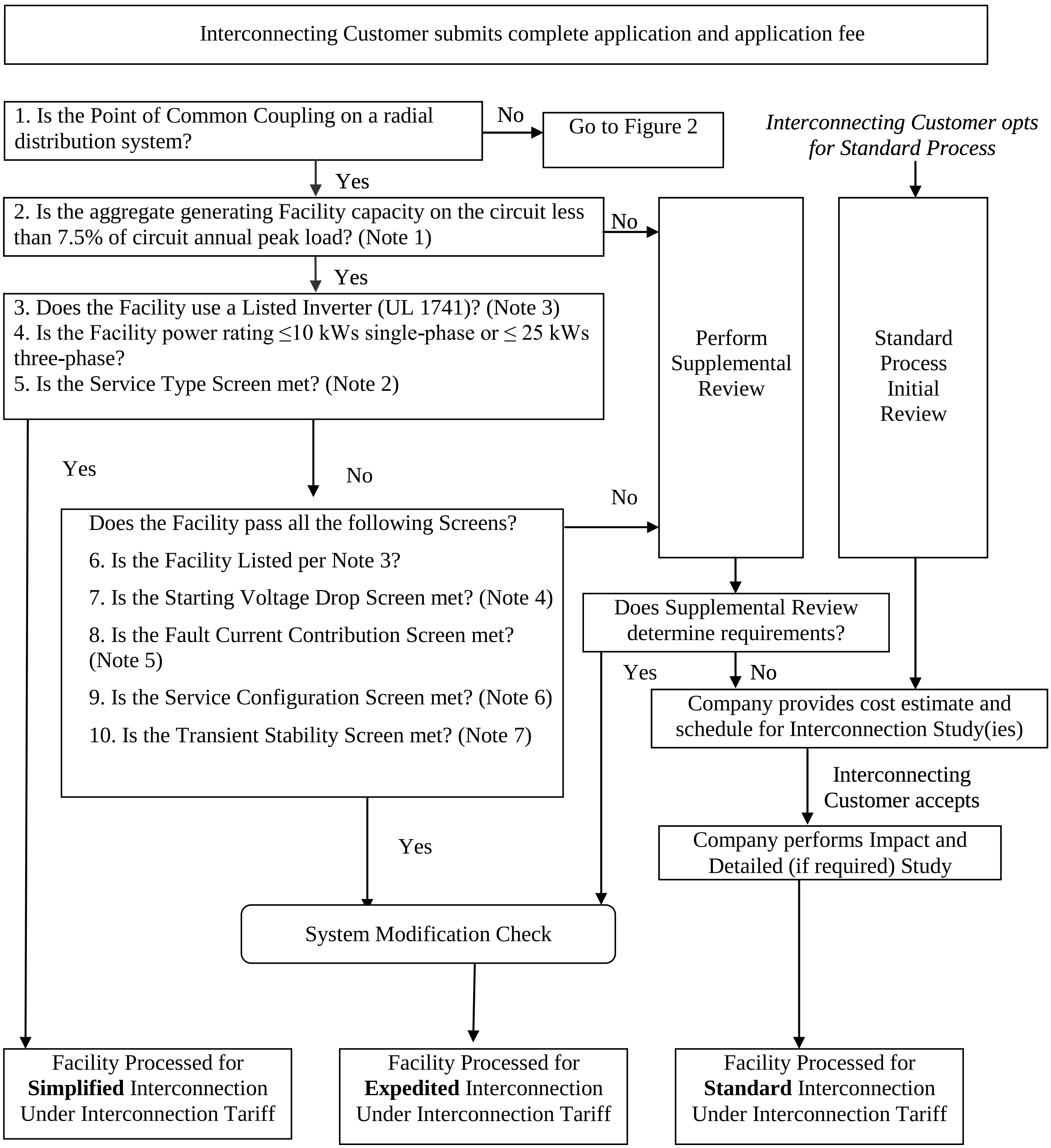
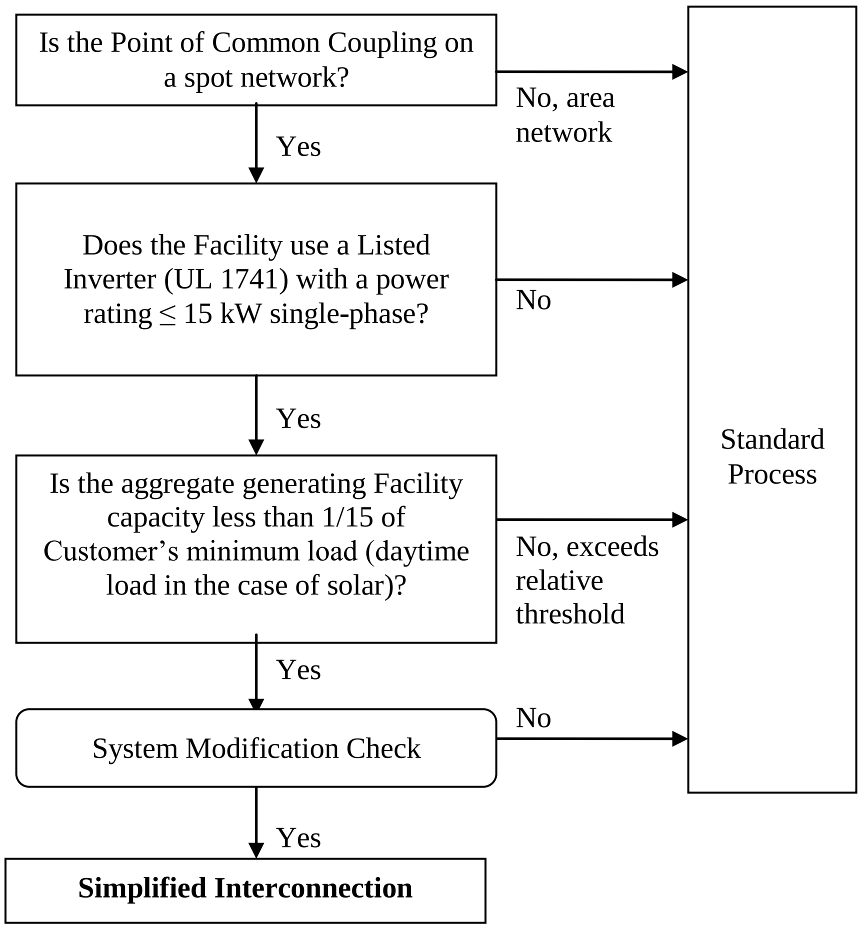


Figure 2 – Simplified Interconnection to Networks



Explanatory Notes to Accompany Figure 1

Note 1. On a typical radial distribution EPS circuit ("feeder") the annual peak load is measured at the substation circuit breaker, which corresponds to the supply point of the circuit. A circuit may also be supplied from a tap on a higher-voltage line, sometimes called a subtransmission line. On more complex radial EPSs, where bidirectional power flow is possible due to alternative circuit supply options ("loop service"), the normal supply point is the loop tap.

Note 2. This screen includes a review of the type of electrical service provided to the Interconnection Customer, including the service transformer configuration and service type to limit the potential for creating unacceptable voltage imbalance, over-voltage or under-voltage conditions, or service equipment overloads on the Company EPS due to a mismatch between the size and phasing of the energy source, the service loads fed from the service transformer(s), and the service equipment ratings.

To be eligible for the Simplified Process, a Listed inverter-based Facility must be either (1) a single-phase unit on a customer's local EPS receiving single-phase secondary service at the PCC from a single-phase service transformer, or (2) a three-phase unit on a customer's local EPS receiving three-phase secondary service at the PCC from a three-phase transformer configuration.

Note 3. A Listed Facility has successfully passed all pertinent tests to conform with IEEE Standard 1547. IEEE Standard 1547 includes design specifications, operational requirements, and a list of tests that are required for Facilities. IEEE Standard 1547.1 describes how to conduct tests to show compliance with provisions of IEEE Standard 1547. To meet Screen 3 or 4, Interconnecting Customers must provide information or documentation that demonstrates how the Facility is in compliance with the IEEE Standard 1547.1 A Facility will be deemed to be in compliance with the IEEE Standard 1547.1 if the Company previously determined it was in compliance. Applicants who can demonstrate Facility compliance with IEEE Standard 1547.1, with the testing done by a nationally recognized testing laboratory, will be eligible for the Expedited Process, and may be eligible for the Simplified process upon review by the utility.

Massachusetts has adopted UL1741 (Inverters, Converters and Charge Controllers for Use in Independent Power Systems) and UL2200 (Stationary Engine Generator Assemblies) as the standard for power systems to comply with IEEE Std 1547 and 1547.1. Equipment listed to UL1741 or UL2200 by a nationally recognized testing laboratory will be considered in compliance with IEEE Std 1547 and 1547.1. An Interconnecting Customer should contact the Facility supplier(s) to determine if it has been listed to either of these standards.

In addition, California and New York have adopted rules for expediting application review and approval of Facility interconnections onto electric distribution systems. Facilities in these states must meet the applicable commission approved tests and/or criteria for expedited procedures in these states. The Company will accept a Facility as eligible for "Listed" and a candidate for the Massachusetts Simplified or Expedited Process if it has been approved for such expedited procedures, or approved for interconnection, in California or New York.

It is the Interconnecting Customer's responsibility to determine if, and submit verification that, the proposed Facility has been so approved in California or New York..

Note 4. This Screen only applies to Facilities that start by motoring the generating unit(s) or the act of connecting synchronous generators. The voltage drops should be less than the criteria below. There are two options in determining whether Starting Voltage Drop could be a problem. The option to be used is at the Company's discretion:

> **Option 1:** The Company may determine that the Facility's starting inrush current is equal to or less than the continuous ampere rating of the Facility's service equipment.
>
> **Option 2:** The Company may determine the impedances of the service distribution transformer (if present) and the secondary conductors to the Facility's service equipment and perform a voltage drop calculation. Alternatively, the Company may use tables or nomographs to determine the voltage drop. Voltage drops caused by starting a generating unit as a motor must be less than 2.5% for primary interconnections and 5% for secondary interconnections.

Note 5. The purpose of this Screen is to ensure that fault (short-circuit) current contributions from all Facilities will have no significant impact on the Company's protective devices and EPS. All of the following criteria must be met when applicable:

a. The proposed Facility, in aggregation with other generation on the distribution circuit, will not contribute more than 10% to the distribution circuit's maximum fault current under normal operating conditions at the point on the high voltage (primary) level nearest the proposed PCC.

b. The proposed Facility, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or Interconnecting Customer equipment on the EPS to exceed 85% of the short-circuit interrupting capability. In addition, the proposed Facility will not be installed on a circuit that already exceeds 85% of the short-circuit interrupting capability.

c. When measured at the secondary side (low side) of a shared distribution transformer, the short-circuit contribution of the proposed Facility must be less than or equal to 2.5% of the interrupting rating of the Company's service equipment.

Coordination of fault-current protection devices and systems will be examined as part of this Screen.

Note 6. This Screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over voltages on the Company EPS due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass Screen
Three-phase, four wire	Effectively-grounded 3 phase or single-phase, line-to-neutral	Pass Screen

If the proposed generator is to be interconnected on a single-phase transformer shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kilovolt-ampere (“kVA”).

If the proposed generator is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.

Note 7. The proposed Facility, in aggregate with other Facilities interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the Facility proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., 3 or 4 transmission voltage level buses from the PCC).

Table 1 – Time Frames (Note 1)

Review Process	**Simplified**	**Expedited**	**Standard**	**Simplified Spot Network**
Eligible Facilities	**Listed Small Inverter**	**Listed DG**	**Any DG**	**Listed Inverter ≤ 15 kW single-phase**
Acknowledge receipt of Application	(3 days)	(3 days)	(3 days)	(3 days)
Review Application for completeness	10 days	10 days	10 days	10 days
Complete Review of all screens	10 days	25 days		Site review 30/90 days (Note 2)
Complete Supplemental Review (if needed)		20 days		
Complete Standard Process Initial Review			20 days	
Send Follow-on Studies Cost/Agreement			5 days	
Complete Impact Study (if needed)			55 days	
Complete Detailed Study (if needed)			30 days	
Send Executable Agreement (Note 3)	Done	10 days	15 days	Done (comparable to Simplified for radial)
Total Maximum Days (Note 4)	15 days	40/ 60 days (Note 5)	125/150 days (Note 6)	40/ 100 days
Notice/ Witness Test	< 1 day with 10 day notice or by mutual agreement	1-2 days with 10 day notice or by mutual agreement	By mutual agreement	1 day with 10- day notice or by mutual agreement

Table 2 – Fee Schedules

	Simplified	**Expedited**	**Standard**	**Simplified Spot Network**
	Listed Small Inverter	**Listed DG**	**Any DG**	**Listed Inverter ≤ 15 kW**
Application Fee (covers Screens)	0 (Note 1)	\$3/kW, minimum \$300, maximum \$2,500	\$3/kW, minimum \$300, maximum \$2,500	≤\$3/kW \$100, >3 kW \$300
Supplemental Review or Additional Review (if applicable)	N/A	Up to 10 engineering hours at \$125/hr (\$1,250 maximum) (Note2)	N/A	N/A
Standard Interconnection Initial Review	N/A	N/A	Included in application fee (if applicable)	N/A
Impact and Detailed Study (if required)	N/A	N/A	Actual cost (Note 3)	N/A
Facility Upgrades	N/A (Note 4)	Actual cost	Actual cost	N/A
O&M (Note 5)	N/A	TBD	TBD	N/A
Witness Test	0	Actual cost, up to \$300 + travel time (Note 6)	Actual Cost	0 (Note 7)

Explanatory Notes to Accompany Tables 1 and 2

Table 1 – Time Frames

Note 1. All days listed apply to Company business days under normal work conditions. All numbers in this table assume a reasonable number of applicants under review. All timelines may be extended by mutual agreement. Any delays caused by Interconnecting Customer will interrupt the applicable clock. Moreover, if an Interconnecting Customer fails to act expeditiously to continue the interconnection process or delays the process by failing to provide necessary information within the longer of 15 days or half the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Interconnecting Customer must reapply. However, the Company will be required to retain the work previously performed in order to reduce the initial and Supplemental Review costs incurred for a period of no less than 1 year. The timelines in Table 1 will be affected if ISO-NE determines that a system impact study is required. This will occur if the Interconnecting Customer's Facility is greater than 5 MW and may occur if the Interconnecting Customer's Facility is greater than 1 MW.

Note 2. 30 days if load is known or can be reasonably determined, 90 days if it has to be metered.

Note 3. Company delivers an executable agreement form. Once the Interconnection Service Agreement is delivered by the Company, any further modification and timetable will be established by mutual agreement.

Note 4. Actual totals laid out in columns exceed the maximum target. The Parties further agree that average days (fewer than maximum days) is a performance metric that will be tracked.

Note 5. Shorter time applies to Expedited Process without Supplemental Review, longer time applies to Expedited Process with Supplemental Review.

Note 6. 125 day maximum applies to an Interconnecting Customer opting to begin directly in Standard Process, and 150 days is for an Interconnecting Customer who goes through initial Expedited Process first. In both cases this assumes that both the Impact and Facilities Studies are needed. If the Detailed Study is not needed, the timelines will be shorter.

Table 2 – Fee Schedules

Note 1. If the Company determines that the Facility does not qualify for the Simplified Process, it will let the Interconnecting Customer know what the appropriate fee is.

Note 2. Supplemental Review and additional review are defined in Section 3.2.

Note 3. This is the actual cost only attributable to the applicant. Any costs not expended from the application fee previously collected will go toward the costs of these studies.

Note 4. Not applicable except in certain rare cases where a System Modification would be needed. If so, the modifications are the Interconnecting Customer's responsibility.

Note 5. O & M is defined as the Company's operations and maintenance carrying charges on the incremental costs associated with serving the Interconnecting Customer.

Note 6. The fee will be based on actual cost up to $300 plus driving time, unless Company representatives are required to do additional work due to extraordinary circumstances or due to problems on the Interconnecting Customer's side of the PCC (e.g., Company representative required to make two trips to the site), in which case Interconnecting Customer will cover the additional cost.

Note 7. Unless extraordinary circumstances.

B. Appendix B – MA DG Interconnection Survey Instruments

Massachusetts Interconnection Stakeholder Survey 2011

Massachusetts Interconnection Stakeholder Survey

Background and Purpose of Study:

At the request of the Massachusetts Department of Energy Resources (DOER), KEMA is working as a consultant to the Massachusetts Clean Energy Center (MassCEC) to review generator experiences with the existing Massachusetts (MA) Distributed Generation (DG) Interconnection process. The purpose of this survey is to identify challenges to the timely interconnection of DG and propose solutions to address those challenges. Your participation in this study is critical in helping to make the MA DG interconnection process more effective. Please respond to this survey at your earliest convenience, but **no later than 5pm ET on Monday April 11, 2011.**

- Respondents must have experience interconnecting distributed generation (DG) systems in Massachusetts. Survey questions assume familiarity with the MA utility Interconnection Tariff. Respondents may find it useful to have a copy of this Tariff on hand during the survey (the tariffs for each utility are available at the “MA DG and Interconnection” website - http://bit.ly/MADGIC).
- Please feel free to send the survey link to others who have had experience with the MA DG Interconnection process.
- If you are interrupted in the middle of the survey, you can resume from your last location, as long as you resume on the same computer.
- To preserve the confidentiality of your replies, do not take the survey on a shared or public computer.
- Respondents may make detailed comments through an Excel spreadsheet that is available at the MA DG Interconnection website. This option is open through April 13.

Massachusetts Interconnection Stakeholder Survey 2011

Opening Questions

How did you find out about this questionnaire?

- Email Announcement from Massachusetts Department of Energy Resources (DOER)
- Email announcement from Massachusetts Clean Energy Center (MassCEC)
- Email announcement from a non-governmental entity
- DOER Website (www.mass.gov/doer)
- The MA DG and Interconnection Website (http://sites.google.com/site/massdgic/)
- Word of mouth

Other (please specify)

* **Are any of your DG interconnection projects completed or in the process of being completed in MA? (We are only seeking participants with interconnection experience in MA at this time.)**

- Yes
- No (Exit survey)

Massachusetts Interconnection Stakeholder Survey 2011

General Information

*** Unless the respondent chooses to opt-out of confidentiality, the data collected from each respondent will not be released in full or in part. The responses you provide in the questionnaire will be aggregated for the purposes of producing the report. Only the report authors will have access to the questionnaire responses.**

- Keep my responses fully confidential. I understand the confidentially policy stated above.
- I would like to partially opt-out of the confidentiality policy: The authors may anonymously quote from my responses (quotes may be used, but the only identification of the source revealed will be a State or region of the country).
- I would like to fully opt-out of the confidentiality policy: The authors may share and quote any of my responses.

What is the name of your organization?

How would you best describe your organization?

- DG Host Customer
- Third-party DG owner
- DG installer

Other (please specify)

What is your role (not your company's role) in the interconnection process?

How many DG interconnection projects in MA have you personally been involved in?

What type of DG projects were they? (Select all that apply)

- Wind
- Solar
- Combined Heat and Power
- Landfill Gas (engines)
- Biomass
- Agriculture Renewable

Other (please specify)

What were the project sizes? (Select all that apply)

- Less than 25 kW
- 25 kW to less than 60 kW
- 60 kW to less than 250 kW
- 250 kW to less than 1 MW
- 1 MW to less than 2MW
- 2MW or greater

In which of the following MA utility service territories have you sought approval to interconnect DG? (Select all that apply)

- National Grid
- NSTAR
- Unitil
- Western Massachusetts Electric Company
- A municipal light plant

* **Which interconnection process(es) have you used? (Select all that apply)**

- Standard Process
- Expedited Process
- Simplified Process
- Not sure or don’t know

Interconnection Process Experience (Simplified Process)

What is the status of your most advanced project?

- Utility acknowledged receipt of application
- Utility reviewed application for completeness
- Completed review of all screens
- Signed executable agreement
- Completed witness test
- Don't know/ Not sure

In your experience, do you think that the interconnection procedures thresholds and approval standards are applied uniformly and consistently among the MA utilities?

- Yes
- No
- Don't know

If no, please provide examples of differences between utilities:

Was your application deemed complete after you submitted it for the first time?

- Yes
- No

If no, how many times did you have to resubmit your application before it was deemed complete?

The interconnection review process is most efficient if the applying DG owner knows the type of distribution circuit into which the project proposes to be interconnected. Did you know the nature of the distribution circuit serving the location of your site prior to submitting your application?

- Yes
- No

If yes, how did you obtain this information?

Have you experienced any delays during the interconnection process?

- Yes
- No

Comments

To what degree, if any, did the following factors contribute to delays during the interconnection process?

	Did not cause delay at all	Minor delay	Major delay	Not applicable
Information needed to initially submit an application				
Utility seeking additional information at various times that were not initially requested in the application				
Customer delays in providing the requested information				
Utility staffing constraints				
Multi-party communication delays caused by customer (eg. lead person vs. decision-makers)				
Multi-party communication delays caused by utility (eg. between different utility departments)				

Other (please specify)

The current process allows the utility to require that an interconnection applicant reapply if the applicant fails to provide necessary information within the longer of 15 days or half the time allotted to the utility to perform a given application step. Do you think this is a reasonable requirement?

- Yes
- No

Comments

Has the interconnecting utility ever asked you for additional information after the initial application was submitted? (Select all that apply)

- Yes, when the application was reviewed for completeness
- Yes, during review of screens
- No

Comments:

How satisfied are you with the clarity and uniformity of the current MA interconnection standards?

Interconnection Standards

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Clarity of the interconnection standards						
Consistency of applying the official Tariff within the same utility						
Uniformity of interconnection standards in practice between different MA utilities						
Transparency of circumstances when DG causes the need for upgrades						
Clarity on state vs federal jurisdiction						

Comment

The existing interconnection process contains several required time limits for the following steps. How satisfied are you with the time required to complete this step in your experience?

Application Process Timeline

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Time to acknowledge receipt of application						
Time to complete initial review						
Time to review all screens						
Time to send executable agreement						
Overall time throughout whole process						

Comment

How satisfied are you with the conduct and capability of the utility personnel with whom you interacted during this process?

Utility personnel

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Professional demeanor						
Technical knowledge						
Clarity of communications						
Responsiveness (timely response to correspondence)						

Comment

Massachusetts Interconnection Stakeholder Survey 2011

Interconnection Standard Policy (Simplified Process)

Currently, the “Simplified” process applies to a) single phase customers with listed single-phase inverter based systems 10 KW or less on radial feed; b) three phase customers with listed three-phase inverter based systems 25 KW or less on radial feed; and c) under some circumstances, a single phase inverter on a spot network system 15 KW or less may be eligible. Are these thresholds reasonable for triggering a “Simplified” review process?

Yes

No

If no, what thresholds would be more appropriate?

Are there requirements in the interconnection process that you consider to be overly burdensome?

Yes

No

If yes, what are they?

Would you support an online application process?

Yes

No

Comments:

What is a reasonable total timeline for the interconnection review process (from when a complete application is submitted to when utility approval is obtained)?

Simplified Process (Enter # of days)

What are reasonable application fees for interconnection? Currently, the application fee for the Simplified Process is $0.

Simplified Process (Enter $)

Do you support an ongoing process involving utilities, DG customers and other stakeholders to continuously improve the interconnection standards/process?

- Yes, through DPU proceedings
- Yes, through stakeholder group
- No

Other (please specify)

Customer Awareness (Simplified Process)

How knowledgeable are you about the existing interconnection process?

- Very knowledgeable
- Somewhat knowledgeable
- Not very knowledgeable

How many DG interconnection workshops or seminars have you personally attended?

Enter #:

How effective are the following informational sources about the interconnection process?

	Extremely ineffective	Somewhat ineffective	Neither effective nor ineffective	Somewhat effective	Extremely effective	Not Applicable/Don't Know
Utility Interconnection Tariff						
Utility interconnection workshops/seminars						
Utility websites						
MA DG and Interconnection website (http://sites.google.com/site/massdgic)						
Utility staff						
DOER staff						

Other (please specify)

How would you like to learn more about the interconnection process? (Select all that apply?)

- Utility workshops
- Utility website
- MA DG and Interconnection website (http://sites.google.com/site/massdgic/)
- Utility staff
- DOER staff

Other (please specify)

How important is it for utilities to provide the following information?

	Not important	Neither important nor unimportant	Somewhat important	Very important	Not Applicable/Don't Know
List of all of the information needed to complete an interconnection application					
Identification of most robust locations for least difficult (and least expensive) siting of DG					
Information regarding system features in different locations (e.g. congestion, substation capacity, fault currents, sensitivities to under and over voltage, etc.)					
Assistance with early screening or identification of complex individual projects before submission of an interconnection application					
More frequent meetings with a DG customer after submission of an interconnection application					
Description of the predominant causes of the need for upgrades and the protocols used to ensure reliability and safety (not site-specific)					
Clarification of state vs federal jurisdiction for the interconnection process					

Please comment on any other issues or concerns that have not been addressed above.

What additional suggestions or thoughts do you have on the interconnection process? Please feel free to include sources, links, models, “best practices”, or anything you like from other states etc.

May we contact you if we have follow-up questions?

- Yes
- No

If yes, please provide your name and contact information (phone number and/or email):

Thank you very much for your time and feedback!

We encourage you to submit more information **no later than April 13** by adding more commentary to your answers using an Excel spreadsheet available at the MA DG and Interconnection website (http://sites.google.com/site/massdgic/). For those interested in referencing sections of the utility Interconnection Tariffs, they are also available at that website.

Massachusetts Interconnection Stakeholder Survey 2011

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Massachusetts Interconnection Stakeholder Survey 2011

General Information

*** Unless the respondent chooses to opt-out of confidentiality, the data collected from each respondent will not be released in full or in part. The responses you provide in the questionnaire will be aggregated for the purposes of producing the report. Only the report authors will have access to the questionnaire responses.**

- Keep my responses fully confidential. I understand the confidentially policy stated above.
- I would like to partially opt-out of the confidentiality policy: The authors may anonymously quote from my responses (quotes may be used, but the only identification of the source revealed will be a State or region of the country).
- I would like to fully opt-out of the confidentiality policy: The authors may share and quote any of my responses.

What is the name of your organization?

How would you best describe your organization?

- DG Host Customer
- Third-party DG owner
- DG installer

Other (please specify)

What is your role (not your company's role) in the interconnection process?

How many DG interconnection projects in MA have you personally been involved in?

What type of DG projects were they? (Select all that apply)

- Wind
- Solar
- Combined Heat and Power
- Landfill Gas (engines)
- Biomass
- Agriculture Renewable

Other (please specify)

What were the project sizes? (Select all that apply)

- Less than 25 kW
- 25 kW to less than 60 kW
- 60 kW to less than 250 kW
- 250 kW to less than 1 MW
- 1 MW to less than 2MW
- 2MW or greater

In which of the following MA utility service territories have you sought approval to interconnect DG? (Select all that apply)

- National Grid
- NSTAR
- Unitil
- Western Massachusetts Electric Company
- A municipal light plant

* Which interconnection process(es) have you used? (Select all that apply)

- Standard Process
- Expedited Process
- Simplified Process
- Not sure or don’t know

Interconnection Process Experience (Expedited Process)

What is the status of your most advanced project?

- Utility acknowledged receipt of application
- Utility reviewed application for completeness
- Completed review of all screens
- Completed supplemental review (if needed)
- Signed executable agreement
- Completed witness test
- Don't know/ Not sure

In your experience, do you think that the interconnection procedures thresholds and approval standards are applied uniformly and consistently among the MA utilities?

- Yes
- No
- Don't know

If no, please provide examples of differences between utilities:

The interconnection review process is most efficient if the applying DG owner knows the type of distribution circuit into which the project proposes to be interconnected. Did you know the nature of the distribution circuit serving the location of your site prior to submitting your application?

- Yes
- No

If yes, how did you obtain this information?

The interconnection application requires significant technical detail regarding the proposed DG equipment before the Application is accepted as "complete". Were you able to provide 100% of this information on your first submittal?

- Yes
- No

If no, why not? What happened after you submitted your application?

Was your application deemed complete after you submitted it for the first time?

- Yes
- No

If no, how many times did you have to resubmit your application before it was deemed complete?

Have you experienced any delays during the interconnection process?

- Yes
- No

Comments

To what degree, if any, did the following factors contribute to delays during the interconnection process?

	Did not cause delay at all	Minor delay	Major delay	Not applicable
Information needed to initially submit an application				
Utility seeking additional information at various times that were not initially requested in the application				
Customer delays in providing the requested information				
Utility staffing constraints				
Equipment upgrade cost negotiations				
Multi-party communication delays caused by customer (eg. lead person vs. decision-makers)				
Multi-party communication delays caused by utility (eg. between different utility departments)				
Equipment/design changes causing further reviews or studies required				

Other (please specify)

The current process allows the utility to require that an interconnection applicant reapply if the applicant fails to provide necessary information within the longer of 15 days or half the time allotted to the utility to perform a given application step. Do you think this is a reasonable requirement?

- Yes
- No

Comments

Has the interconnecting utility ever asked you for additional information after the initial application was submitted? (Select all that apply)

- Yes, when the application was reviewed for completeness
- Yes, during review of screens
- Yes, during supplemental review (if needed)
- No

Comments:

Which types of impacts were noted by the utility review?

- Over or under voltage
- Frequency control (including harmonics)
- Reverse power protection
- Fault protection
- Impact on the grid from loads occurring from a breaker trip

Other (provide brief description)

How satisfied are you with the clarity and uniformity of the current MA interconnection standards?

Interconnection Standards

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Clarity of the interconnection standards						
Consistency of applying the official Tariff within the same utility						
Uniformity of interconnection standards in practice between different MA utilities						
Transparency of circumstances when DG causes the need for upgrades						
Clarity on state vs federal jurisdiction						

Comment

How reasonable are the costs of interconnecting DG in MA?

Cost of Interconnection

	Very reasonable	Somewhat reasonable	Neither reasonable or unreasonable	Somewhat unreasonable	Very unreasonable	Not Applicable/Don't Know
Cost of application fee/initial review						
Cost of supplemental review						
Cost of interconnection equipment required						
Cost of facility upgrades (to the distribution system)						
Cost of operations and maintenance (O&M)						
Cost of witness testing and commissioning						

Comment

The existing interconnection process contains several required time limits for the following steps. How satisfied are you with the time required to complete this step in your experience?

Application Process Timeline

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Time to acknowledge receipt of application						
Time to complete initial review						
Time to review all screens						
Time to complete supplemental review and send follow-on studies regarding cost/agreement						
Time to send executable agreement						
Overall time throughout whole process						

Comment

How satisfied are you with the conduct and capability of the utility personnel with whom you interacted during this process?

Utility personnel

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Professional demeanor						
Technical knowledge						
Clarity of communications						
Responsiveness (timely response to correspondence)						

Comment

Interconnection Standard Policy (Expedited Process)

Currently, the "Simplified" process applies to a) single phase customers with listed single-phase inverter based systems 10 KW or less on radial feed; b) three phase customers with listed three-phase inverter based systems 25 KW or less on radial feed; and c) under some circumstances, a single phase inverter on a spot network system 15 KW or less may be eligible. Are these thresholds reasonable for triggering a "Simplified" review process?

- Yes
- No

If no, what thresholds would be more appropriate?

Currently, expedited review applies to Listed Facilities that pass certain pre-specified screens on a radial electric power system. Have you found these thresholds to be a reasonable basis for triggering an "Expedited" review process?

- Yes
- No

If no, what thresholds would be more reasonable?

Are there requirements in the interconnection process that you consider to be overly burdensome?

- Yes
- No

If yes, what are they?

Would you support an online application process?

- Yes
- No

Comments

What is a reasonable total timeline for the interconnection process (from when a complete application is submitted to when utility approval is obtained)?

Simplified Process(Enter # of days)

Expedited Process(Enter # of days)

What are reasonable application fees for interconnection? Currently, application fee for simplified review is $0; the application fee for expedited review is $3/kW with a minimum of $300 and maximum of $2500.

Simplified Process (Enter $)

Expedited Process (Enter $)

In the Expedited Process, what is a reasonable fee for the Supplemental Review? Currently, it is $125/hour for up to 10 engineering hours.

How should utilities determine what to charge DG owners/customers for distribution upgrades if growth-related upgrades are anticipated in the planning horizon (e.g., approximately 5 years)?

How should the assignment of upgrade costs be structured?

- Current policy (generally, the DG customer pays for whatever upgrades are required to interconnect the individual generator)
- Policy restructured to adjust to allow multiple small projects (less than 6 MW) on a single circuit to share upgrade costs

Other:

Is the current alternative dispute resolution (ADR) process effective?

- Yes
- No
- Not applicable or don't know

If no, what do you recommend?

Do you support an ongoing process involving utilities, DG customers and other stakeholders to continuously improve the interconnection standards/process?

- Yes, through DPU proceedings
- Yes, through stakeholder group
- No

Other (please specify)

Massachusetts Interconnection Stakeholder Survey 2011

Customer Awareness (Expedited Process)

How knowledgeable are you about the existing interconnection process?

- Very knowledgeable
- Somewhat knowledgeable
- Not very knowledgeable

How many DG interconnection workshops or seminars have you personally attended?

Enter #:

How effective are the following informational sources about the interconnection process?

	Extremely ineffective	Somewhat ineffective	Neither effective nor ineffective	Somewhat effective	Extremely effective	Not Applicable/Don't Know
Utility Interconnection Tariff						
Utility interconnection workshops/seminars						
Utility websites						
MA DG and Interconnection website (http://sites.google.com/site/massdgic)						
Utility staff						
DOER staff						

Other (please specify)

How would you like to learn more about the interconnection process? (Select all that apply?)

- Utility workshops
- Utility website
- MA DG and Interconnection website (http://sites.google.com/site/massdgic/)
- Utility staff
- DOER staff

Other (please specify)

How important is it for utilities to provide the following information?

	Not important	Neither important nor unimportant	Somewhat important	Very important	Not Applicable/Don't Know
List of all of the information needed to complete an interconnection application					
Identification of most robust locations for least difficult (and least expensive) siting of DG					
Information regarding system features in different locations (e.g. congestion, substation capacity, fault currents, sensitivities to under and over voltage, etc.)					
Assistance with early screening or identification of complex individual projects before submission of an interconnection application					
More frequent meetings with a DG customer after submission of an interconnection application					
Description of the predominant causes of the need for upgrades and the protocols used to ensure reliability and safety (not site-specific)					
Clarification of state vs federal jurisdiction for the interconnection process					

What additional suggestions or thoughts do you have on the interconnection process? Please feel free to include sources, links, models, "best practices", or anything you like from other states etc.

What additional suggestions or thoughts do you have on the interconnection process? Please feel free to describe other sources, link to materials, models, suggestions of places they can mention "best practices", things you like from other states etc.

May we contact you if we have follow-up questions?

- Yes
- No

If yes, please provide your name and contact information (phone number and/or email):

Thank you very much for your time and feedback!

We encourage you to submit more information **no later than April 13** by adding more commentary to your answers using an Excel spreadsheet available at the MA DG and Interconnection website (http://sites.google.com/site/massdgic/). For those interested in referencing sections of the utility Interconnection Tariffs, they are also available at that website.

Massachusetts Interconnection Stakeholder Survey 2011

Massachusetts Interconnection Stakeholder Survey

Background and Purpose of Study:

At the request of the Massachusetts Department of Energy Resources (DOER), KEMA is working as a consultant to the Massachusetts Clean Energy Center (MassCEC) to review generator experiences with the existing Massachusetts (MA) Distributed Generation (DG) Interconnection process. The purpose of this survey is to identify challenges to the timely interconnection of DG and propose solutions to address those challenges. Your participation in this study is critical in helping to make the MA DG interconnection process more effective. Please respond to this survey at your earliest convenience, but **no later than 5pm ET on Monday April 11, 2011.**

- Respondents must have experience interconnecting distributed generation (DG) systems in Massachusetts. Survey questions assume familiarity with the MA utility Interconnection Tariff. Respondents may find it useful to have a copy of this Tariff on hand during the survey (the tariffs for each utility are available at the “MA DG and Interconnection” website - http://bit.ly/MADGIC).
- Please feel free to send the survey link to others who have had experience with the MA DG Interconnection process.
- If you are interrupted in the middle of the survey, you can resume from your last location, as long as you resume on the same computer.
- To preserve the confidentiality of your replies, do not take the survey on a shared or public computer.
- Respondents may make detailed comments through an Excel spreadsheet that is available at the MA DG Interconnection website. This option is open through April 13.

Massachusetts Interconnection Stakeholder Survey 2011

Opening Questions

How did you find out about this questionnaire?

- Email Announcement from Massachusetts Department of Energy Resources (DOER)
- Email announcement from Massachusetts Clean Energy Center (MassCEC)
- Email announcement from a non-governmental entity
- DOER Website (www.mass.gov/doer)
- The MA DG and Interconnection Website (http://sites.google.com/site/massdgic/)
- Word of mouth

Other (please specify)

* **Are any of your DG interconnection projects completed or in the process of being completed in MA? (We are only seeking participants with interconnection experience in MA at this time.)**

- Yes
- No (Exit survey)

Massachusetts Interconnection Stakeholder Survey 2011

General Information

*** Unless the respondent chooses to opt-out of confidentiality, the data collected from each respondent will not be released in full or in part. The responses you provide in the questionnaire will be aggregated for the purposes of producing the report. Only the report authors will have access to the questionnaire responses.**

- Keep my responses fully confidential. I understand the confidentially policy stated above.
- I would like to partially opt-out of the confidentiality policy: The authors may anonymously quote from my responses (quotes may be used, but the only identification of the source revealed will be a State or region of the country).
- I would like to fully opt-out of the confidentiality policy: The authors may share and quote any of my responses.

What is the name of your organization?

How would you best describe your organization?

- DG Host Customer
- Third-party DG owner
- DG installer

Other (please specify)

What is your role (not your company's role) in the interconnection process?

How many DG interconnection projects in MA have you personally been involved in?

What type of DG projects were they? (Select all that apply)

- Wind
- Solar
- Combined Heat and Power
- Landfill Gas (engines)
- Biomass
- Agriculture Renewable

Other (please specify)

What were the project sizes? (Select all that apply)

- Less than 25 kW
- 25 kW to less than 60 kW
- 60 kW to less than 250 kW
- 250 kW to less than 1 MW
- 1 MW to less than 2MW
- 2MW or greater

In which of the following MA utility service territories have you sought approval to interconnect DG? (Select all that apply)

- National Grid
- NSTAR
- Unitil
- Western Massachusetts Electric Company
- A municipal light plant

* **Which interconnection process(es) have you used? (Select all that apply)**

- Standard Process
- Expedited Process
- Simplified Process
- Not sure or don’t know

Interconnection Process Experience (Standard Process)

What is the status of your most advanced project?

- Utility acknowledged receipt of application
- Utility reviewed application for completeness
- Completed Standard Process initial review
- Signed follow-on studies cost/agreement
- Completed impact study (if needed)
- Completed detailed study (if needed)
- Signed executable agreement
- Completed witness test
- Don't know/ Not sure

In your experience, do you think that the interconnection procedures thresholds and approval standards are applied uniformly and consistently among the MA utilities?

- Yes
- No
- Don't know

If no, please provide examples of differences between utilities:

The interconnection review process is most efficient if the applying DG owner knows the type of distribution circuit into which the project proposes to be interconnected. Did you know the nature of the distribution circuit serving the location of your site prior to submitting your application?

- Yes
- No

If yes, how did you obtain this information?

The interconnection application requires significant technical detail regarding the proposed DG equipment before the application is accepted as “complete”. Were you able to provide 100% of this information on your first submittal?

- Yes
- No

If no, why not? What happened after you submitted your application?

Was your application deemed complete after you submitted it for the first time?

- Yes
- No

If no, how many times did you have to resubmit your application before it was deemed complete?

Have you experienced any delays during the interconnection process?

- Yes
- No

Comments

To what degree, if any, did the following factors contribute to delays during the interconnection process?

	Did not cause delay at all	Minor delay	Major delay	Not applicable
Information needed to initially submit an application				
Utility seeking additional information at various times that were not initially requested in the application				
Customer delays in providing the requested information				
Customer delays in approving costs for Impact Study and/or upgrades				
Utility staffing constraints				
Equipment upgrade cost negotiations				
Multi-party communication delays caused by customer (eg. lead person vs. decision-makers)				
Multi-party communication delays caused by utility (eg. between different utility departments)				
Equipment/design changes causing further reviews or studies required				

Other (please specify)

The current process allows the utility to require that an interconnection applicant reapply if the applicant fails to provide necessary information within the longer of 15 days or half the time allotted to the utility to perform a given application step. Do you think this is a reasonable requirement?

- Yes
- No

Comments

Has the interconnecting utility ever asked you for additional information after the initial application was submitted? (Select all that apply)

- Yes, when application was reviewed for completeness
- Yes, during Standard Process Initial Review
- Yes, during impact study
- Yes, during detailed study
- No

Comments

Have you ever been required to provide data on your proposed project to assist the utility in modeling its impacts?

- Yes
- No

If yes, what type of data was requested? Please comment on any factors or conditions that may have required this data.

Which types of impacts were noted by the utility review? (Select all that apply)

- Over or under voltage
- Frequency control (including harmonics)
- Reverse power protection
- Fault protection
- Impact on the grid from loads occurring from a breaker trip

Other (provide brief description)

How satisfied are you with the clarity and uniformity of the current MA interconnection standards?

Interconnection Standards

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Clarity of the interconnection standards						
Consistency of applying the official Tariff within the same utility						
Uniformity of interconnection standards in practice between different MA utilities						
Transparency of circumstances when DG causes the need for upgrades						
Clarity on state vs federal jurisdiction						

Comment

How reasonable are the costs of interconnecting DG in MA?

Cost of Interconnection

	Very unreasonable	Somewhat unreasonable	Neither reasonable nor unreasonable	Somewhat reasonable	Very reasonable	Not Applicable/Don't Know
Cost of application fee/initial review						
Cost of supplemental review						
Cost of impact and detailed study						
Cost of interconnection equipment required						
Cost of facility upgrades (to the distribution system)						
Cost of operations and maintenance (O&M)						
Cost of witness testing and commissioning						

Comment

The existing interconnection process contains several required time limits for the following steps. How satisfied are you with the time required to complete this step in your experience?

Application Process Timeline

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Time to acknowledge receipt of application						
Time to complete initial review						
Time to review all screens						
Time to complete supplemental review and send follow-on studies regarding cost/agreement						
Time to complete impact study						
Time to complete detailed study						
Time to send executable agreement						
Overall time throughout whole process						

Comment

How satisfied are you with the conduct and capability of the utility personnel with whom you interacted during this process?

Utility personnel

	Very unsatisfied	Somewhat unsatisfied	Neither satisfied nor dissatisfied	Somewhat satisfied	Very satisfied	Not Applicable/Don't Know
Professional demeanor						
Technical knowledge						
Clarity of communications						
Responsiveness (timely response to correspondence)						

Comment

Interconnection Standard Policy (Standard Process)

Currently, the “Simplified” process applies to a) single phase customers with listed single-phase inverter based systems 10 KW or less on radial feed; b) three phase customers with listed three-phase inverter based systems 25 KW or less on radial feed; and c) under some circumstances, a single phase inverter on a spot network system 15 KW or less may be eligible. Are these thresholds reasonable for triggering a “Simplified” review process?

- Yes
- No

If No, what thresholds would be more appropriate?

Currently, expedited review applies to Listed Facilities that pass certain pre-specified screens on a radial electric power system. Have you found these thresholds to be a reasonable basis for triggering an “Expedited” review process?

- Yes
- No

If no, what thresholds would be more reasonable?

Are there requirements in the interconnection process that you consider to be overly burdensome?

- Yes
- No

If yes, what are they?

Would you support an online application process?

- Yes
- No

Comments

What is a reasonable total timeline for the interconnection process (from when a complete application is submitted to when utility approval is obtained?

Simplified Process(Enter # of days)

Expedited Process(Enter # of days)

Standard Process(Enter # of days)

What are reasonable application fees for interconnection? Currently, application fee for the Simplified Process is $0; the application fee for Expedited Process and Standard Process is $3/kW with a minimum of $300 and maximum of $2500.

Simplified Process(Enter $)

Expedited Process(Enter $)

Standard Process(Enter $)

In the expedited process, what is a reasonable fee for the supplemental review? Currently, it is $125/hour for up to 10 engineering hours.

Enter $:

In the standard process, what is a reasonable fee for the impact and detailed study? Currently, they are at actual cost.

Impact Study (Enter $ amount or % of actual cost)

Detailed Study (Enter $ amount or % of actual cost)

How should utilities determine what to charge DG owners/customers for distribution upgrades if growth-related upgrades are anticipated in the planning horizon (e.g., approximately 5 years)?

How should the assignment of upgrade costs be structured?

- Current policy (generally, the DG customer pays for whatever upgrades are required to interconnect the individual generator)
- Policy restructured to adjust to allow multiple small projects (less than 6 MW) on a single circuit to share upgrade costs

Comments:

Is the current alternative dispute resolution (ADR) process effective?

- Yes
- No
- Not applicable or don’t know

If no, what do you recommend?

Do you support an ongoing process involving utilities, DG customers and other stakeholders to continuously improve the interconnection standards/process?

- Yes, through DPU proceedings
- Yes, through stakeholder group
- No

Other (please specify)

Customer Awareness (Standard Process)

How knowledgeable are you about the existing interconnection process?

- Very knowledgeable
- Somewhat knowledgeable
- Not very knowledgeable

How many DG interconnection workshops or seminars have you personally attended?

Enter #:

How effective are the following informational sources about the interconnection process?

	Extremely ineffective	Somewhat ineffective	Neither effective nor ineffective	Somewhat effective	Extremely effective	Not Applicable/Don't Know
Utility Interconnection Tariff						
Utility interconnection workshops/seminars						
Utility websites						
MA DG and Interconnection website (http://sites.google.com/site/massdgic)						
Utility staff						
DOER staff						

Other (please specify)

How would you like to learn more about the interconnection process? (Select all that apply?)

- Utility workshops
- Utility website
- MA DG and Interconnection website (http://sites.google.com/site/massdgic/)
- Utility staff
- DOER staff

Other (please specify)

How important is it for utilities to provide the following information?

	Not important	Neither important nor unimportant	Somewhat important	Very important	Not Applicable/Don't Know
List of all of the information needed to complete an interconnection application					
Identification of most robust locations for least difficult (and least expensive) siting of DG					
Information regarding system features in different locations (e.g. congestion, substation capacity, fault currents, sensitivities to under and over voltage, etc.)					
Assistance with early screening or identification of complex individual projects before submission of an interconnection application					
More frequent meetings with a DG customer after submission of an interconnection application					
Description of the predominant causes of the need for upgrades and the protocols used to ensure reliability and safety (not site-specific)					
Clarification of state vs federal jurisdiction for the interconnection process					

Please comment on any other issues or concerns that have not been addressed above.

What additional suggestions or thoughts do you have on the interconnection process? Please feel free to describe other sources, link to materials, models, suggestions of places they can mention “best practices”, things you like from other states etc.

May we contact you if we have follow-up questions?

- Yes
- No

If yes, please provide your name and contact information (phone number and/or email):

Massachusetts Interconnection Stakeholder Survey 2011

Thank you very much for your time and feedback!

We encourage you to submit more information **no later than April 13** by adding more commentary to your answers using an Excel spreadsheet available at the MA DG and Interconnection website (http://sites.google.com/site/massdgic/). For those interested in referencing sections of the utility Interconnection Tariffs, they are also available at that website.

C. Appendix C – Utility Interview Guide

MA DG Interconnection Study – Utility Interview Guide

Interview Tracking Information

Interviewer		Interview Length (min.)	
Completion Date			

Contact Information

Contact Name	
Contact Title	
Company Name	
City, State, Zip	
Phone	
Alt info (email, cell)	

Call Tracking

Date/Time	Notes/result/actions: (Who spoke to, new contact info, when to call back, etc.)

Preamble

- My name is [Erika or Fran]. I am working with KEMA on study of DG Interconnection issues for MA Department of Energy Resources and MA Clean Energy Center.
- This interview is confidential. Nothing you say will be attributed to you. We will not link your name or your company's name with your words in any way[1]. Please confirm that you are in a private office with the door closed.
- There are three main objectives to this call – we hope to:
  - Get your answer to some of the questions asked on the recent DG IC survey;
  - Get your perspective on challenges in the MA interconnection process; and
  - Get your thoughts on possible changes you think might be required if the pace of interconnection activity continues to increase.
- We seek *your opinion* and understand that it is your personal opinion only. We do not expect you to speak in any way for your company or for the other MA utilities.
- This interview has three main sectionswhich we want to complete in 45 minutes. To do so, I must ask you to synthesize your answer to just a few sentences. If you have more detail than that, I will ask you to send me an email with that additional information later – make sense?

[1](We cannot of course guarantee that our interview notes or results couldn't be obtained by regulatory or legal actions.) While we *cannot* guarantee this, there is such a small probability of this occurring that mentioning it is unnecessary.

Part One: The Current Process [15 minutes – 5 questions, 2 long ones!]

To start, the first part of this interview looks at the current process. We will do that through the 'lens' of a single IC application and its review process.

Please recall a recent **Standard** Process IC application with which you are familiar, on a project which is now interconnected. This project should not be either "best case" or "worst case", but "typical" -- one that can illuminate the 'challenges' in the current system.

Please choose from your own personal experience.

1. Please describe this Standard application: size, DG/technology type; type of circuit; type of applicant.
2. Roughly how long did this review process take, from the time you received a completed application to the time you sent an executable Interconnection Agreement?
3. What was the **single longest step** in your review of this specific IC application(regardless of whether that step was longest by design or not)?
    a. Please describe this step generally.
    b. Please estimate the duration [in terms of days or weeks, as appropriate].
    c. How long would you have expected this step to take? [if the *longest step* took exactly the time anticipated and had *no delays,* skip to **Question 5.]**

Next I want to delve into the details of this *longest step,* as it unfolded in this specific instance.

4. To what degree, if any, did the following factors contribute to the time required to complete this step in this specific instance? Please say whether each factor caused:

    "No Delay" (ND); "Small Delay"(SD); "Major Delay"(MD); or Not Applicable (NA).

    [If respondent questions the word "delay" then define as "time above the time specified for each step in the tariff's Time Frame Table" (Table 1).]

    a. Customer time to provide required information during this step, i.e. information specified/requiredin the application
    b. Customer time to provide more detailed or additional information, over and above that requested in the application?
    c. Multi-party communication delays caused by customer (e.g.between the lead person and other decision-makers)
    d. Multi-party communication delays within the utility company (e.g. between different departments)
    e. Utility staffing constraints – i.e., insufficient personnel within the department(s) carrying the responsibilities for this step.
    f. Time spent assessing/discussing state/federal jurisdiction or the possible need for ISO review
    g. Time spent in the process of securing ISO review
    h. Field visits or inspections (if any during this step)
    i. Other [any significant factor that caused delay that has not been discussed]
5. Given the screens in the tariff, when questions of judgment arise about whether a specific screen has been passed, what do you do?

6. In your opinion, could any of the thresholds in the screens (i.e., 2 and 6 through 10) be changed to reduce the number of projects which require Supplemental Review? If so, which ones?
7. Are there changes in the thresholds or screens 2 through 5 (e.g., 7.5%, 10/25 KW) that you could suggest to enable projects currently processed under the Expedited Process to be treated under the Simplified Process? If so, what changes to which screens?
8. To wrap up this review of the current process, to what extent do you think that interconnection thresholds and approval standards are implemented uniformly across the MA utilities? Please use a 10-point scale, where 0 is there is no consistency and 10= 100% consistency across all 4.

Part Two: Related Topics [15 minutes; 9 questions]

FERC-jurisdiction

9. How do you handle an application that might be FERC-jurisdictional?
   a. Who [in company] makes that determination?
   b. Who/ what party informs ISO-NE? Who is the contact at ISO-NE? How is this notification handled?
   c. What happens if there is a disagreement about jurisdiction?
10. What changes would you suggest to improve the review of IC applications on FERC-jurisdictional lines?

Interconnecting to Networks

11. In 2010, roughly how many applications did you receive for interconnection to a Spot network?
    a. How many of these were for projects that were eligible for the Simplified Spot Network process?
12. In 2010, did you receive any applicationsfor interconnection to an Area Network, Yes/No.
    a. If so, how many? [[if they won't estimate, ask "was it more than 5? Less than 2?" Also if not zero and they can't provide the number, request a follow-up email with that info.]]
13. Roughly how many *inquiries* did you receive about DG projects for locations on an Area Network? [[if they won't estimate, ask "was it more than 5? Less than 2?" Also if not zero and they can't provide the number, request a follow-up email with that info.]]

System Modifications

14. Roughly how many Expedited applications were you personally involved in, since January 2010? How many Standard IC applications?
15. Of the Expedited applications you reviewed….
    a. Roughly what percentage failed technical screens and were thereby reviewed under the Standard process?
    b. Roughly what percentage required a significant modification to the distribution system to accommodate the interconnection? –[define "significant" as a modification with a cost charged to the customer]
16. Of the Standard applications you reviewed, roughly what percentage required a significant modification to accommodate the interconnection?

Cost Allocation

The tariff currently requires that DG owners be charged the cost of upgrades to the distribution system needed to handle their interconnection.

17. How should charges to DG owners be determined ***if*** growth-related upgrades are anticipated in the planning horizon (e.g., approximately 5 years)?

    [Limit time to short answer, accept referral to someone else in the company if respondent prefers not to answer.]

Part Three: Looking Ahead [15 minutes]

In the next set of questions, I want to look at the internal processes used to handle the volume of DG applications [[Company]] receives. There are three subsets here, past, present and future.

18. Returning to your 'longest step' example above, what specific internal departments or groups were involved in this review process? [please list them all, by name]

    a. Optional probe: Does [Company] have a specialized department to coordinate DG applications? If so, please describe how this group works with other departments.

Clearly, the quality of the application review process is core and not to be jeopardized. Given that, many in the industry would like to see the approval process speeded up. Next I have a list of changes that could be made, in the hopes enabling you to complete the same quality of review more quickly.

19. Again, holding the quality of the review constant, please give each of the following a score, based on whether you think it would improve the speed of the review process. Please use a ten-point scale where 0 is defined as "will not improve the speed one bit" and 10 is defined as "would improve the process *a lot*".

    a. Use of an online application process

    b. Pre-application consultation or other means of immediate feedback regarding possible fatal flaws for a proposed project

    c. Applicant allowed to provide (at their cost) consulting engineers from a list pre-approved by utility to work under utility direction to model or otherwise assist the review process;

    d. A "Batch" process, to accept and cluster the applications received during a specified period. These batched applications would be reviewed in one or more groups as appropriate.

    e. Technology-differentiated schedules and processes– e.g., different timelines/schedules for different types of DG, according to the evidence they provide in their application of ability to pass 'all' screens;

    f. Publish a map of distribution circuits showing 'average time for IC approval' based on the type of network/circuit.

    g. Use of an auction for priority treatment. For example, for qualified/ eligible Standard projects, with eligibility criteria transparent and published, set up minimum number of available 6-month 'slots' for large-project review; auction these off each quarter. Auction proceeds pay for utility-hired consultants to *guarantee* that the review is completed within that period.

    h. Other --

Now, we'll look into the future. Imagine that it is 2013. The number of IC applications you [Company] is receiving is twice what it was in 2010.

20. What changes in your internal processes have been or must be made to handle this volume in a timely manner?
    a. What other changes – internal or external – might be needed to manage this volume of growth?

Part Four: Optional Questions *If time remains*

21. During the IC application review process, when the ball is in your court (e.g., the pause button is not pressed), what are the sources of delay in your process? [same definition of 'delay'-- "time above the time specified for each step in the tariff's Time Frame Table]]
22. Overall, the industry is concerned about the overall length of the time required for the full interconnection process, from the point of application to the energized system. Do you have any other suggestions to improve this process, that we haven't already discussed?
23. To end, let me give you a metaphorical magic wand. Imagine that you DO have the power of magic and can make *any change you want* to the manner in which the interconnection of DG systems is handled. What three things would you change?
    a. ..
    b. ..
    c.
24. Do you have any final comments about the IC process in your Company, present or future?

Wrap-Up question

Ask of everyone, no matter whether optional Qs have been asked--

If we find that we have failed to ask any critical questions, may we follow up with you?

IF this is needed, it would most likely take the form of one or two questions that could be answered in writing at your convenience.

Short and even possibly by email. IF needed. Would that be OK?

Thank you very much for your time!

D. Appendix D – State/Federal Jurisdictional Clarifications

Does the Interconnection Request go to ISO-NE?

The definition of Interconnection Request in Schedule 23 of ISO's tariff provides guidance. Any request to a signatory of the Transmission Operating Agreement (TOA) that meets this definition should go to ISO-NE. Many, but not all, municipal utilities are signatories to the TOA.

Schedule 23 states that "Interconnection Request (a) shall mean an Interconnection Customer's request, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) increase the energy capability or capacity capability of an existing Generating Facility; (iii) make a modification to the operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected to the Administered Transmission System; (iv) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System; or (v) change from NR Interconnection Service to CNR Interconnection Service for all or part of a Generating Facility's capability. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility."

Schedule 23 defines Administered Transmission System as "The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff."
From Order FERC 2003:

804. This Final Rule applies to interconnections to the facilities of a public utility's Transmission System that, at the time the interconnection is requested, may be used either to transmit electric energy in interstate commerce or to sell electric energy at wholesale in interstate commerce pursuant to a Commission-filed OATT.**128** In other words, the standard

interconnection procedures and contract terms adopted in this Final Rule apply when an Interconnection Customer that plans to engage in a sale for resale in interstate commerce or to transmit electric energy in interstate commerce requests interconnection to facilities owned, controlled, or operated by the Transmission Provider or the Transmission Owner, or both, that are used to provide transmission service under an OATT that is on file at the Commission at the time the Interconnection Request is made. Therefore, the Final Rule applies to a request to interconnect to a public utility's facilities used for transmission in interstate commerce. It also applies to a request to interconnect to a public utility's "distribution" facilities used to transmit electric energy in interstate commerce on behalf of a wholesale purchaser pursuant to a Commission-filed OATT. But where the "distribution" facilities have a dual use, i.e., the facilities are used for both wholesale sales and retail sales, the Final Rule applies to interconnections to these facilities only for the purpose of making sales of electric energy for resale in interstate commerce.**129**

ISO-NE depends on the distribution company to determine if there is an existing wholesale transaction on the distribution circuit where the new interconnection will be made.

Any increase to the MW output of a generator participating in the ISO markets requires an Interconnection Request to ISO-NE.

Generation Interconnection Responsibilities
ISO New England Proposal
Updated by ECNE Distributed Generation Forum 9/11/08 - Approved by ISO (with comment) 9/25/08

								Company Involvement in study			Company Involvement in IA			In ISO
Row #	Intent to Sell to Market at time of Application [2]	Rate Class at POI at Time of Application	Generator Size (Net)	Interconnect Process	Receives Request	Responsible [6] for Application	Administers Deposit	Dist Co	T.O.	ISO-NE	Dist Co	T.O.	ISO-NE	Queue
1	No	Distribution	< 5MW	Utility	Dist. Utility	Dist. Utility	Dist. Utility	Lead [4]	Participant [5]	Not Involved	Signs	None	None	No
2	No	Distribution	> = 5 MW	Utility	Dist. Utility	Dist. Utility	Dist. Utility	Lead [4]	Participant	Participant [8]	Signs	None	None	Yes
3	No	Trans (Non-PTF)	< 5MW	Utility	Trans. Utility	Trans. Utility	Trans. Utility	Participant	Lead [4,5]	Not Involved	None	Signs	None	No
4	No	Trans. (PTF)	< 5MW	Utility	Trans. Utility	Trans. Utility	Trans. Utility	Participant	Lead [4,5]	Participant [7]	None	Signs	None	No
5	No	Trans. (PTF or Non-PTF)	> = 5 MW	Utility	Trans. Utility	Trans. Utility	Trans. Utility	Participant	Lead [4]	Participant [8]	None	Signs	None	Yes
6	Yes	Distribution not under FERC Jurisdiction [1]	< 5MW	Utility	Dist. Utility	Dist. Utility	Dist. Utility	Lead [4]	Participant [5]	Not Involved	Signs	None	None	No
7	Yes	Distribution not under FERC Jurisdiction [1]	> = 5 MW	Utility	Dist. Utility	Dist. Utility	Dist. Utility	Lead [4]	Participant	Participant [8]	Signs	None	None	Yes
8	Yes	Distribution under Under FERC Jurisdiction [3]	0 -20 MW [8]	Sched 23	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead [4]	Signs	None	Signs	Yes
9	Yes	Distribution under FERC jurisdiction [3]	> 20 MW	Sched 22	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead [4]	Signs	None	Signs	Yes
10	Yes	Trans. (PTF or Non-PTF) [3]	0 - 20 MW [8]	Sched 23	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead [4]	None	Signs	Signs	Yes
11	Yes	Trans. (PTF or Non-PTF) [3]	> 20 MW	Sched 22	ISO-NE	ISO-NE	ISO-NE	Participant	Participant	Lead [4]	None	Signs	Signs	Yes

(1) A distribution facility is FERC jurisdictional when used to supply wholesale power or becomes FERC jurisdictional when a generating facility making wholesale sales interconnects. The first interconnection request to a non FERC jurisdictional line falls under the state procedures, whether they intend to make wholesale transactions or not.

(2) For the purposes of Sched 22 & Sched 23, an Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a non-FERC jurisdictional distribution facility and the Interconnection Customer does not intend to make wholesale sales; or (iii) a request to interconnect a Qualifying Facility, where the owner intends to sell 100% of the output to its host utility.

(3) Functional pass through of "local" service/interconnection applications as described in Article 3.03(a)(ii) of the TOA, paraphrased below. ISO forwards application to appropriate PTO. ISO reviews application to determine whether interconnection would have impact on facilities used for the provision of regional transmission service (PTF). If yes, the ISO performs studies to address impacts on facilities used for the provision of regional transmission service (PTF). The PTO is responsible for performing studies to address impacts on local facilities.

(4) The Lead is responsible for informing ISO, for meeting study deadlines, arranging for contractors if needed, etc.

(5) T.O. is responsible to notify ISO of situations where multiple small generators may have cumulative impacts. File notification PP5.1 Appendix 4 for projects greater than 1 MW but less than 5 MW.
In addition all
generators (less

(6) Interconnection Customer can contact ISO to help resolve questions concerning what entity is responsible for the application.

(7) ISO should participate in the study as it is responsible for impacts on (and interconnections to) the facilities used for the provision of regional transmission service (PTF).

(8) File Proposed Plans (I.3.9), for any application > or equal to 5MW, because there is a potential impact on the transmission system.

Definitions:

IA = Interconnition Agreement
ISO-NE = Independent System Operator - New England
POI = Point of Interconnection
PP5.1 = ISO-NE Proposed Plan 5.1 form
PTF = Pool Transmission Facility
PTO = Participating Transmission Owner
Sched 22 = ISO-NE Generator Interconnection Standard process for large Generators
Sched 23 = ISO-NE Generator Interconnection Standard process for small Generators
TO = Transmission Owner
TOA = Transmission Operating Agreement

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